The following table provides operating income by segment for the year ended December 31, 2005:

	Reorganized NRG						
	For the Year Ended December 31, 2005						
	Northeast	South Central	Western	Other North America	Australia	All Other	Total
	(In millions, except MWh, CDD and HDD data)						
Energy revenue	$ 1,444	$ 330	$ 1	$ 11	$ 144	$ 84	$2,014
Capacity revenue	291	186	—	5	—	81	563
Hedging & risk management activity	(285)	(1)	—	—	43	(5)	(248)
Alternative revenue	—	—	—	2	—	189	191
O&M fees	—	—	—	—	—	20	20
Other revenue	104	37	—	(3)	25	5	168
Operating revenues	1,554	552	1	15	212	374	2,708
Cost of energy	871	368	1	14	93	182	1,529
Derivative cost of energy	(2)	—	—	—	—	—	(2)
Other operating expenses(1)	393	104	5	16	99	121	738
Depreciation and amortization	74	61	1	7	27	24	194
Operating income/(loss)	218	20	(6)	(28)	(7)	41	238
MWh sold(2) (in thousands)	16,128	11,710	6	77	5,495		
Market indicators:							
Average natural gas price — Henry Hub ($/MMbtu)							$ 8.89
Average on-peak market power prices ($/MWh)	$ 91.98	$ 69.96	$ 71.06	$ 63.76			
Cooling Degree Days, or CDDs(3)	1,604	2,825	776	970			
CDD's 30 year rolling average	1,073	2,449	704	708			
Heating Degree Days, or HDDs(3)	10,449	1,638	2,563	5,095			
HDD's 30 year rolling average	10,479	1,888	2,790	5,436			

(1) Other operating expenses include "Cost of majority-owned operations" and "General, administrative and development" expenses, excluding cost of energy.

(2) Includes MWhs sold for wholly owned subsidiaries only.

(3) National Oceanic and Atmospheric Administration-Climate Prediction Center — A CDD represents the number of degrees that the mean temperature for a particular day is above 65 degrees Fahrenheit in each region. An HDD represents the number of degrees that the mean temperature for a particular day is below 65 degrees Fahrenheit in each region. The CDDs/HDDs for a period of time are calculated by adding the CDDs/HDDs for each day during the period.

The following table provides operating income by segment for the year ended December 31, 2004:

	Reorganized NRG						
	For the Year Ended December 31, 2004						
	Northeast	South Central	Western	Other North America	Australia	All Other	Total
	(In millions, except MWh, CDD and HDD data)						
Energy revenue	$ 853	$ 219	$ 10	$ 15	$ 159	$ 109	$1,365
Capacity revenue	265	183	(4)	84	—	84	612
Hedging & risk management activity	58	—	—	1	15	2	76
Alternative revenue	—	—	—	2	—	174	176
O&M fees	—	—	—	—	—	21	21
Other revenue	75	16	(3)	(8)	7	11	98
Operating revenues	1,251	418	3	94	181	401	2,348
Cost of energy	521	223	5	10	79	168	1,006
Derivative cost of energy	—	—	—	—	—	—	—
Other operating expenses(1)	338	71	5	42	83	154	693
Depreciation and amortization	73	62	1	21	24	27	208
Operating income/(loss)	318	58	(9)	(5)	(5)	36	393
MWh sold(2) (in thousands)	14,259	10,569	77	5	5,189		
Market indicators:							
Average natural gas price — Henry Hub ($/MMbtu)							$ 5.89
Average on-peak market power prices ($/MWh)	$ 63.53	$ 45.76	$ 53.16	$ 43.31			
Cooling Degree Days, or CDDs(3)	1,031	2,547	888	590			
CDD's 30 year rolling average	1,073	2,449	704	708			
Heating Degree Days, or HDDs(3)	10,256	1,557	2,347	4,987			
HDD's 30 year rolling average	10,479	1,888	2,790	5,436			

(1) Other operating expenses include "Cost of majority-owned operations" and "General, administrative and development" expenses, excluding cost of energy.

(2) Includes MWhs sold for wholly owned subsidiaries only.

(3) National Oceanic and Atmospheric Administration-Climate Prediction Center — A CDD represents the number of degrees that the mean temperature for a particular day is above 65 degrees Fahrenheit in each region. An HDD represents the number of degrees that the mean temperature for a particular day is below 65 degrees Fahrenheit in each region. The CDDs/HDDs for a period of time are calculated by adding the CDDs/HDDs for each day during the period.

The following table provides operating income by segment for the period December 6, 2003 through December 31, 2003:

	Reorganized NRG						
	For the Period from December 6, 2003 through December 31, 2003						
	Northeast	South Central	Western	Other North America	Australia	All Other	Total
	(In millions, except MWh, CDD and HDD data)						
Energy revenue	$ 49	$ 15	$ —	$ —	$ 10	$ (10)	$ 64
Capacity revenue	14	11	—	5	—	7	37
Hedging & risk management activity	—	—	—	—	2	—	2
Alternative revenue	—	—	—	—	—	12	12
O&M fees	—	—	—	—	—	1	1
Other revenue	6	1	—	(1)	—	15	21
Operating revenues	69	27	—	4	12	25	137
Cost of energy	28	15	—	—	6	14	63
Derivative cost of energy	—	—	—	—	—	—	—
Other operating expenses(1)	25	4	—	3	4	9	45
Depreciation and amortization	5	3	—	2	1	1	12
Operating income/(loss)	11	4	—	—	—	—	15
Market indicators:							
Average natural gas price — Henry Hub ($/MMbtu)							$6.28
Average on-peak market power prices ($/MWh)	$ 60.75	$ 39.98	$ 49.08	$ 33.09			
Cooling Degree Days, or CDDs(3)	—	—	—	—			
CDD's 30 year rolling average	1,073	2,449	704	708			
Heating Degree Days, or HDDs(3)	1,494	377	427	803			
HDD's 30 year rolling average	10,479	1,888	2,790	5,436			

(1) Other operating expenses include "Cost of majority-owned operations" and "General, administrative and development" expenses, excluding cost of energy.

(2) Includes MWhs sold for wholly owned subsidiaries only.

(3) National Oceanic and Atmospheric Administration-Climate Prediction Center — A CDD represents the number of degrees that the mean temperature for a particular day is above 65 degrees Fahrenheit in each region. An HDD represents the number of degrees that the mean temperature for a particular day is below 65 degrees Fahrenheit in each region. The CDDs/HDDs for a period of time are calculated by adding the CDDs/HDDs for each day during the period.

Upon our emergence from bankruptcy, we adopted the Fresh Start Reporting provisions of SOP 90-7. Accordingly, the Reorganized NRG statement of operations and statement of cash flows have not been prepared on a consistent basis with the Predecessor Company's financial statements and are not comparable in certain respects to the financial statements prior to the application of Fresh Start, therefore, the Predecessor Company's and the Reorganized NRG's amounts are discussed separately for comparison and analysis purposes, herein.

The following table provides operating income by segment for the period January 1, 2003 through December 5, 2003:

	Predecessor NRG						
	For the Period from January 1, 2003 through December 5, 2003						
	Northeast	South Central	Western	Other North America	Australia	All Other	Total
	(in millions, except MWh, CDD and HDD data)						
Energy revenue	$ 554	$ 196	$ 5	$ 9	$ 122	$ 24	$ 910
Capacity revenue	235	160	19	74	—	78	566
Hedging & risk management activity	19	—	—	—	—	—	19
Alternative revenue	—	—	—	2	—	80	82
O&M fees	—	—	—	2	—	11	13
Other revenue	53	1	—	(1)	29	126	208
Operating revenues	861	357	24	86	151	319	1,798
Cost of energy	470	188	4	7	72	104	845
Derivative cost of energy	4	—	—	—	(9)	—	(5)
Other operating expenses(1)	326	59	4	39	61	195	684
Depreciation and amortization	90	34	11	30	17	29	211
Operating income/(loss)	(1,331)	(384)	(101)	(465)	(68)	5,734	3,385
Market indicators:							
Average natural gas price — Henry Hub ($/MMbtu)							$ 5.43
Average on-peak market power prices ($/MWh)	$ 61.78	$ 41.53	$ 48.64	$ 37.83			
Cooling Degree Days, or CDDs(3)	1,164	2,583	900	633			
CDD's 30 year rolling average	1,073	2,449	704	708			
Heating Degree Days, or HDDs(3)	11,404	1,836	2,455	5,586			
HDD's 30 year rolling average	10,479	1,888	2,790	5,436			

(1) Other operating expenses include "Cost of majority-owned operations" and "General, administrative and development" expenses, excluding cost of energy.

(2) Includes MWhs sold for wholly owned subsidiaries only.

(3) National Oceanic and Atmospheric Administration-Climate Prediction Center — A CDD represents the number of degrees that the mean temperature for a particular day is above 65 degrees Fahrenheit in each region. An HDD represents the number of degrees that the mean temperature for a particular day is below 65 degrees Fahrenheit in each region. The CDDs/HDDs for a period of time are calculated by adding the CDDs/HDDs for each day during the period.

For year ended December 31, 2005 compared to the year ended December 31, 2004

Significant Events Reflected in our Results of Operations During 2005

- Extreme weather conditions, including Hurricanes Katrina and Rita, contributed to the increase in the sale price of power. This increase in power prices drove the net mark-to-market losses of $119 million primarily associated with forward financial electric sales in support of our Northeast assets.
- As compared to the year ended December 31, 2004, on-peak electricity prices increased between 43% to 53% in the various markets we operate, whereas our total domestic coal costs, which are largely contracted, increased only 17% increasing our dark spreads. Gas and oil prices increased 50% and 49%, respectively, resulting in higher spark spreads, but compressed oil margins as compared to the same period last year[1]
- Total generation increased for the year ended December 31, 2005 compared to 2004 by 5%.
- We began selling excess emission allowances, and have recognized a net gain of $31 million during 2005.
- Forced outages at our Huntley, Dunkirk, Indian River and Big Cajun II plants during 2005 negatively impacted our generation by 2.4 million MWh.
- We repurchased $645 million in aggregate principal amount of our Second Priority Notes, resulting in $45 million of refinancing charges.
- We sold a number of non-core assets including, Enfield, our Northbrook assets and our remaining Kendall interest for a total of $106 million in proceeds and a net gain of approximately $32 million.
- We announced the signing of a sale agreement for Rocky Road resulting in an impairment charge of $20 million.
- We wrote-down our interest in the Saguaro Power Company by $27 million.

Consolidated Discussion:

Revenues from Majority-Owned Operations

Revenues from majority-owned operations were $2,708 million for the year ended December 31, 2005 compared to $2,348 million for the year ended December 31, 2004, an increase of $360 million. Energy revenues for the year ended December 31, 2005 increased $649 million from $1,365 million to $2,014 million. Of the $2,014 million, 87% were merchant as compared to 70% for the year ended December 31, 2004. The increase in energy revenues versus 2004 was driven by both increased prices and the increased merchant generation from our Northeast assets. Energy revenues from our domestic coal assets increased by $314 million, all due to increased power prices, as generation from our domestic coal assets decreased 5% for the year ended December 31, 2005 as compared to the same period in 2004. This decrease in generation was due to both planned and unplanned outages at Huntley, Indian River, and Big Cajun II during the second and fourth quarters, and the time we typically perform outage work. Energy revenue from our gas assets in New York City increased by $176 million, including $23 million in NYISO final settlement payments. Of the remaining $153 million, both price and generation nearly equally contributed to the increase. Energy revenues from our oil-fired assets rose by $211 million, 86% due to higher volumes following an increase in summer demand as the generation from these assets increased by 122% for the year ended December 31, 2005 as compared to the same period in 2004. Additionally, a one-time payment of $39 million from the Connecticut Light and Power settlement contributed to energy revenue during the second quarter of 2004.

Capacity revenues for the year ended December 31, 2005 were $563 million compared to $612 million for the year ended December 31, 2004, a reduction of $49 million. Capacity revenues were unfavorable versus last year due to the loss of $56 million capacity revenues from the Kendall facility, which was sold in the fourth

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[1] Per the Henry Hub gas price index published by *Platts Gas Daily*.

quarter of 2004, and the expiration of the Rockford tolling agreement in May 2005 which reduced year-on-year results by $23 million. Capacity revenues from our western New York plants decreased by $10 million due to the addition of new generation and increased imports in New York, which depressed capacity prices for our assets in the western New York market during the first half of 2005. This loss was offset by a $44 million increase in capacity revenues from our Connecticut assets. This increase is related to the additional $24 million capacity revenues recorded in 2005 related to our Connecticut RMR settlement agreement. Alternative revenues for the year ended December 31, 2005 and 2004 were $191 million and $175 million, respectively. Increased generation due to the hotter weather this summer and an increase in contract rates from our Thermal and Resource Recovery operations positively impacted the alternative revenues results.

Other revenues include emission allowance sales, natural gas sales, Fresh Start-related contract amortization, and expense recovery revenues. For the year ended December 31, 2005, other revenues totaled a $168 million compared to $98 million of other revenues for the same period in 2004. The increase is due to higher emission allowance revenues, higher physical gas sales and lower contract amortization, offset by lower expense recovery revenues. Please see our discussion below as to our emission allowance position and sales. The increase in other revenues was also attributed to $33 million in higher gas sales. The increase in gas sales is primarily related to a new gas sale agreement entered into in the third quarter of 2005 by the South Central region, where revenues from gas sales increased by $23 million. We entered into this agreement in conjunction with power purchase agreements to minimize our market purchases during peak months. Lower contract amortization of $30 million is related to contracts rolling off over the course of time. Finally, during the year ended December 31, 2005, expense recovery revenues were $29 million lower versus the comparable period in 2004. Expense recovery revenues are associated with our Connecticut RMR agreements and we reached our maximum payment under that agreement during the first quarter of 2005.

Sale of Excess SO_2 Emission Allowances — We actively manage our surplus emission allowance position. During the later half of 2005, we began trading a portion of our excess SO_2 emission allowances to third parties. Revenues from the sale of emission allowances to third parties net of purchases totaled $31 million in 2005, excluding the EPA auction results. The following table provides the sales activity and our balance of emission allowances (excluding Texas Genco) for vintage years, through 2009:

	Tons	Average Sales Price	Revenue
Balance of NRG SO_2 Emissions Credits Allowances, as of December 31, 2004	897,653	n/a	n/a
Sales during 2005	35,052	$ 889	$31 million
Consumed	(115,810)		
Balance of NRG SO_2 Emissions Credits Allowances, as of December 31, 2005	746,791	n/a	n/a
Completed Sales between January 1 and February 28, 2006	46,077	$1,180	$54 million
Balance of NRG SO_2 Emissions Credits Allowances, as of February 28, 2006	700,714	n/a	n/a

In addition to our SO_2 emission allowance balances presented above, after the closing of the acquisition of Texas Genco, the combined NRG balance of excess SO_2 emissions allowances for vintage years through 2009 is 1,329,066 tons on February 28, 2006.

We expect to continue the active management of our SO_2 emission allowances in excess of our forecast generation needs.

Hedging and Risk Management Activity

	For the Year Ended December 31, 2005						
	Northeast	South Central	Western	Other North America	Australia	All Other	Total
				(In millions)			
Net gains/(losses) on settled positions, or financial revenues	$ (132)	$ (1)	$ —	$ —	$ 35	$ (5)	$(103)
Mark-to-market results							
Reversal of previously recognized unrealized (gains)/losses on settled positions	(59)	—	—	—	1	—	(58)
Net unrealized gains/(losses) on open positions related to economic hedges	(119)	—	—	—	7	—	(112)
Net unrealized gains/(losses) on open positions related to trading activity	27	—	—	—	—	—	27
Subtotal mark-to-market results	(151)	—	—	—	8	—	(143)
Total derivative gain/(loss)	$ (283)	$ (1)	$ —	$ —	$ 43	$ (5)	$(246)

Hedging and Risk Management Activity — The total derivative loss for the year was approximately $246 million, comprised of $103 million in financial revenue losses and $143 million of mark-to-market losses. The $103 million loss of financial revenues represent the settled value for the year of all financial instruments including but not limited to financial swaps on power. Of the $143 million of mark-to-market losses, $112 million represents the change in fair value of forward sales of electricity and fuel — $114 million losses associated with electricity sales and $2 million gain associated with cost of fuel, the reversal of $58 million of mark-to-market gains which ultimately settled as financial revenues and $27 million mark-to-market gain related to trading activity. These activities primarily support our Northeast assets. The $112 million domestic loss related to forward sales during 2005 compares to a $59 million gain for the same period during 2004.

Since our economic hedging activities are intended to mitigate the risk of commodity price movements on revenues and cost of energy sold, the changes in such results should not be viewed in isolation, but rather taken together with the effects of pricing and cost changes on energy revenues and costs of energy. In the fourth quarter of 2004 and over the course of 2005, we hedged much of our calendar year 2005 and 2006 Northeast generation. Since that time and during the third quarter 2005 in particular, the settled and forward prices of electricity rose, driven by the extreme weather conditions this summer. While this increase in electricity prices benefited our generation portfolio versus last year with higher energy revenues, it is also the reason for the mark-to-market recognition of the forward sales and the settlement of positions as losses.

In addition to the hedging techniques used until now, we expect to utilize hedging strategies that are option-based with a goal of establishing a floor on earnings, leaving upside market participation, minimizing mark-to-market swings and optimizing collateral support of our hedging program. For 2007, we have already locked in a floor on 30% of our baseload coal generation at current forward prices while preserving our ability to benefit from further upward movement in northeastern electricity prices.

Cost of Majority-Owned Operations

Cost of majority-owned operations for the year ended December 31, 2005 was $2,067 million. Cost of majority-owned operations for the year ended December 31, 2004 was $1,489 million or 63% of revenues from majority-owned operations. The increase is related to the cost of energy, which increased by $521 million, to $1,529 million or 56% of revenues for the year ended December 31, 2005 from $1,008 million or 43% of revenues for the same period in 2004. The increase in the cost of energy as a percentage of revenues is driven by the higher mark to market loss in revenues, by both higher price and generation in the Northeast region and higher purchased energy and gas sales in the South Central region. Total gas costs increased by $163 million, $124 million in the New York City assets alone. Of the increase at our New York City assets, $15 million was due to increased gas purchases for resale, with approximately $67 million due to increased generation. The

South Central region's gas costs increased by $25 million due to physical gas purchases related to a new gas sale agreement entered into in the third quarter of 2005 to support certain tolling arrangements. Total oil costs for the company increased by $165 million, 65% due to increased generation from our oil-fired assets, and the remainder due to an increase in price. Total coal costs increased by $71 million. The increase at our domestic coal-fired assets is solely due to price increases, as overall generation from our coal-fired assets decreased for the year ended December 31, 2005 by 5% as compared to the same period in 2004 due to the planned and forced outages at our Huntley, Indian River and Big Cajun II facilities. The increase in coal prices is related to new low-sulfur coal and rail contracts which became effective in April 2005. Additionally, our Indian River plant uses a higher portion of eastern coal that experienced a significant cost increase in 2005. We have increased our percentage blend of low-sulfur coal over the year as compared to the same period last year. This had the effect of mitigating the increase in coal and coal transportation costs as low sulfur coal prices have not increased as much as regular coal prices. Total purchased energy increased by $112 million due to increases at our South Central region. Higher long-term contract load demand due to the extreme weather, a 100-MW around-the-clock sale to Entergy, a tolling agreement, and the forced outages during the second quarter, required South Central to purchase energy to meet its contract load obligations.

Other Operating Expenses during 2005 totaled $737 million versus $693 million in the comparable period of 2004, an increase of $44 million. This increase is driven by a $51 million, or 11%, increase in operating and maintenance costs. Major maintenance projects and more extensive outages in 2005, as compared to 2004, contributed $33 million to the increase. The low-sulfur coal conversions and turbine overhauls of the western New York plants and Indian River plant was a main focus for many of the major maintenance and outages in 2005. South Central also went through a significant outage to install a low-NOX burner on one of its units and an additional outage was completed this Fall to address reliability issues experienced at the Big Cajun II unit earlier in the year. Normal maintenance increased by $9 million or 9% due to the increased run time at our plants this summer. Additionally, in 2004, a settlement with a third party vendor regarding auxiliary power charges reduced 2004 operating and maintenance expenses by $7 million.

Depreciation and Amortization

Our depreciation and amortization expense for the year ended December 31, 2005 and 2004 was approximately $194 million and $208 million, respectively. The decrease in depreciation and amortization from 2005 to 2004 is due to the 2004 sale of our Kendall plant, which contributed approximately $14 million in depreciation and amortization expense during 2004.

General, Administrative and Development

Our G&A costs for the year ended December 31, 2005 were $197 million compared to $210 million for the same period in 2004, a decrease of $13 million. Corporate costs represent $94 million or 3% of revenues and $113 million or 5% of revenues for the years ended December 31, 2005 and 2004, respectively. G&A costs have been favorably impacted by $11 million in reduced bad debt expense associated with notes receivable from third parties. Additionally, external consulting expenses decreased in 2005 as compared to 2004 by approximately $11 million primarily related to reduced tax and legal consulting. These favorable impacts were offset by a $5 million increase in information technology related expenses primarily associated with increased compliance costs related to Sarbanes Oxley and the relocation from Minneapolis.

Corporate Relocation Charges

During the year ended December 31, 2005, charges related to our corporate relocation activities were approximately $6 million as compared to $16 million in 2004. Included in this year's charges is approximately $3 million related to the lease abandonment charges associated with our former Minneapolis office with the remainder related to the relocation, recruitment and transition costs. In 2004, we recorded $16 million primarily related to employee severance and termination benefits and employee-related transition costs. We completed the physical move of our relocation in 2004 when the majority of costs were incurred. We do not expect any material relocation charges in 2006.

Equity in Earnings of Unconsolidated Affiliates

During the year ended December 31, 2005, equity earnings from our investments in unconsolidated affiliates were $104 million compared to $160 million for the year ended December 31, 2004, a decrease of $56 million. Our earnings in WCP accounted for $22 million and $69 million for the years ended December 31, 2005 and 2004, respectively. The decrease in WCP's equity earnings is due to the expiration of the CDWR contract in December 2004. Enfield's equity earnings were $13 million lower for the year ended December 31, 2005 as compared to the same period in 2004. We sold our investment in Enfield on April 1, 2005. For the year ended December 31, 2005 results for Enfield include approximately $12 million of unrealized gains associated with mark-to-market increases in the fair value of energy-related derivative instruments, as compared to $23 million of unrealized gain for the same period of 2004.

Other equity investments included in the 2005 results include MIBRAG and Gladstone which comprised $26 million and $24 million for the year ended December 31, 2005, respectively. For the comparable period in 2004, MIBRAG and Gladstone earned $21 million and $18 million, respectively. MIBRAG's equity earnings for 2004 were negatively impacted by an outage at our Schkopau plant; additionally, MIBRAG recorded a lower asset retirement obligation in 2005 as compared to 2004. Gladstone's earnings in 2005 were greater than 2004 due to lower major maintenance expense and an approximate $1 million recovery in business interruption insurance.

Write Downs and Gains/(Losses) on Sales of Equity Method Investments

During the year ended December 31, 2005, we recorded a $31 million loss due to the sale and impairment of certain equity investments as we continued to divest of non-core assets. On April 1, 2005, we sold our 25% interest in Enfield, resulting in net pre-tax proceeds of $65 million and a pre-tax gain of $12 million, including the post-closing working capital adjustments. In 2005, we also sold our interest in Kendall for $5 million in net pre-tax proceeds and a pre-tax gain of approximately $4 million. These gains on sales were offset by approximately $47 million in impairment charges recorded this year.

In December 2005, we executed an agreement with Dynegy to sell our 50% interest in Rocky Road LLC in conjunction with our purchase of Dynegy's 50% interest in WCP. Based on this arms length transaction rendering the fair value of our investment in Rocky Road at $45 million, we subsequently impaired our investment to this fair value by an approximate write down of $20 million. We expect to close the sale of our interest of Rocky Road during the first half of 2006. We also recorded an impairment of $27 million on our investment in Saguaro. With the expiration of its gas supply contract, Saguaro began recording operating losses during the second half of 2005, triggering a permanent write down to NRG's investment value in Saguaro.

During the year ended December 31, 2004, we sold our Loy Yang investment which resulted in a $1 million loss, our interest in Commonwealth Atlantic Limited Partnership for a $5 million loss, and several NEO investments for a $4 million loss. These losses were offset by a $1 million gain associated with the sale of Calpine Cogeneration. Also during 2004, we recorded a $7 million impairment charge on our investment in James River LLC based on an estimated sale value from a prospective buyer.

Other Income, net

Other income had a net increase of $35 million during the year ended December 31, 2005 as compared to the same period in 2004. Other income in 2005 was favorably impacted by a $14 million gain from the settlement related to our TermoRio project in Brazil and a gain of approximately $4 million related to the resolution of a contingency from the sale of a former project, the Crockett Cogeneration Facility, which was sold in 2002. Other income was also favorably impacted by $14 million of higher interest income related to more efficient management of our cash balances. These favorable results were offset by a $3 million reserve relating to the ongoing TermoRio litigation.

Refinancing expense

Refinancing expenses for the year ended December 31, 2005 and 2004 were $56 million and $72 million, respectively. During 2005, as part of our continuing effort to manage our capital structure, we redeemed and purchased a total of $645 million of our Second Priority Notes. As a result of the redemption and purchases, we incurred $55 million in premiums and write-offs of deferred financing costs. Our Australia region also refinanced its project debt for better terms, resulting in the write-off of approximately $10 million of debt premium, i.e. refinancing income. We also incurred an additional $11 million in refinancing fees during 2005 related to the amortization of a bridge loan commitment fee that we paid related to the Acquisition of Texas Genco.

As part of our new financing in 2006 in conjunction with the acquisition of Texas Genco, we paid a bridge loan commitment fee of approximately $45 million to ensure that we would have the proper financing in place for the said acquisition. This amount is being amortized over time, and during 2005 we amortized approximately $11 million to refinancing expense. The remaining balance of this amount will be expensed during the first quarter of 2006 as we finalized the new financings related to the acquisition of Texas Genco.

During the year ended December 31, 2004, we refinanced certain amounts of our term loans with additional corporate level high yield notes for better terms, which resulted in $15 million of prepayment penalties and a $15 million write-off of deferred financing costs. Additionally, we refinanced our senior credit facility in December 2004 and recorded $14 million of prepayment penalties and a $27 million of write-off of deferred financing costs.

Interest expense

Interest expense for the year ended December 31, 2005 was $197 million as compared to $266 million for the same period in 2004, a reduction of $69 million. Interest expense was favorably impacted by the sale of Kendall which incurred $25 million of interest expense year ended December 31, 2004. Additionally, the refinancing of our Senior Credit Facility on December 23, 2004 lowered our interest rate by 212.5 basis points and the $645 million redemption and purchases of our Second Priority Notes during 2005 reduced interest expense on our corporate debt by approximately $50 million.

Income Tax Expense

Income tax expense was approximately $43 million and approximately $65 million for the years ended December 31, 2005 and 2004, respectively. The overall effective tax rate was 35.8% and 28.7% for the years ended December 31, 2005 and 2004, respectively. The effective income tax rate for the year ended December 31, 2005 and 2004 differs from the U.S. statutory rate of 35% due to the earnings in foreign jurisdictions taxed at rates lower than the U.S. statutory rate, rendering an effective tax rate of 17.3% and 9.7%, respectively, on foreign income. Our 2005 domestic income tax effective rate increased due to our gain on the sale of Enfield and the taxable dividend received pursuant to the American Jobs Creation Act of 2004. Also see our tax rate reconciliation disclosure in Note 22, *Income Taxes*, to the Condensed Consolidated Financial Statements.

The effective tax rate may vary from period to period depending on, among other factors, the geographic and business mix of earnings and losses and the adjustment of valuation allowances in accordance with SFAS 109. These factors and others, including our history of pre-tax earnings and losses, are taken into account in assessing the ability to realize deferred tax assets.

Income from Discontinued Operations, net of Income Taxes

During the year ended December 31, 2005 and 2004, we recorded a gain from discontinued operations of $7 million and $25 million, respectively, as we continued to divest certain non-core assets. Discontinued operations for the year ended December 31, 2005 consist of Audrain, the Northbrook New York and Northbrook Energy assets and various expenses related to the final settlements of McClain. During the year ended December 31, 2004, discontinued operations consisted of the results of Audrain, the two Northbrook entities, McClain, Penobscot Energy Recovery Company, or PERC, Compania Boliviana De Energia Electrica S.A. Bolivian Power Company Limited, or Cobee, Hsin Yu, LSP Energy (Batesville) and four NEO Corporation projects (NEO Nashville LLC, NEO Hackensack LLC, NEO Prima Deshecha and NEO Tajiguas LLC). With the exception of Audrain, Northbrook New York and Northbrook Energy, all discontinued operations were sold prior to December 31, 2004.

As of December 31, 2005, the sale of Audrain is still pending and remains subject to regulatory approvals. Ameren's application to assume certain obligations of Audrain is pending before the Missouri Public Service Commission . The case filed with the FERC seeking authorization for the transaction pursuant to section 203 of the Federal Power Act has been protested by the Missouri Joint Municipal Electric Utility Commission. The pre-merger waiting period under the Hart-Scott-Rodino Antitrust Improvement Act expired January 19, 2006. Despite the above, we still expect to close this sale during the first half of 2006.

Regional Discussion

Northeast Region Results

Operating Income

For the year ended December 31, 2005, operating income for the Northeast region was $218 million, as compared to $318 million for the same period in 2004, a decrease of $100 million. This decrease is due to $119 million net MTM losses reported by the Northeast associated with forward sales of electricity as compared to a $59 million net MTM gain booked in 2004. Excluding net MTM losses or gains, the Northeast operating income increased by $52 million. This increase was largely due to increased power prices, wider dark spread margins, and increased generation from the Northeast gas and oil assets. With higher than average temperatures this summer, on-peak electricity prices increased 43% to 52% as compared to 2004, while gas and oil prices increased 50% and 49%[1] Spark spreads on our gas and coal margins widened, while oil margins were compressed compared to the same period last year. The Northeast's New York City assets benefited from the increased spark spreads as they increased their generation output by 52% versus last year, from 1.1 million MWh to 1.7 million MWh due to increased summer demand. Generation from our Northeast oil-fired assets increased by 122%, but oil margins decreased by 25% versus 2004, as our cost per MWh increased by 29% in comparison to the same period in 2004 due to an offsetting increase in oil prices.

Revenues

Revenues from our Northeast region totaled $1,554 million for the year ended December 31, 2005 compared to $1,251 million for the same period in 2004, an increase of $303 million. Revenues for the year ended December 31, 2005 included $1,444 million in energy revenues compared to $853 million for the same period in 2004. Of this $591 million increase, $183 million can be attributed to our New York City assets. Due to outages of local competitors and extreme heat this summer, sold generation from our New York City assets' increased by 52% for the year ended December 31, 2005 as compared to 2004. Excluding the $23 million of final NYISO settlement payments, increased generation accounted for 49% of the increase in NYC energy revenues. Our oil-fired assets earned $211 million more in energy revenues, and increased generation 122% during 2005 as compared to 2004; 86% of the increased energy revenues were due to increased generation. Our coal assets recorded higher energy revenues of $99 million due solely to higher power prices as generation from our coal assets had a minimal decrease for the year ended December 31, 2005.

Capacity revenues for the year ended December 31, 2005 were $291 million compared to $265 million for the same period in 2004. Capacity revenues were favorable versus the last year due to $24 million additional capacity revenues recorded during the second quarter of 2005 in conjunction with our Connecticut RMR settlement agreement approved by FERC on January 22, 2005. These settlement revenues were offset, however, by lower capacity revenues from our western New York plants. Capacity prices in western New York were negatively impacted by the addition of new capacity supply and increased imports into the state.

[1]Per the Henry Hub gas price index published by *Platts Gas Daily*.

Other revenues include emission credit sales, natural gas sales, Fresh Start-related contract amortization, and expense recovery revenues and totaled $104 million for the year ended December 31, 2005 as compared to $75 million the same period in 2004, an increase of $29 million. This increase is related to the additional $43 million in emission allowance sales to both external parties and inter-company sales. In addition, other revenues increased from $6 million in higher gas sales, and $6 million in lower contract amortization as the contracts have rolled off over time. Other revenues were adversely impacted by $29 million in lower expense recovery revenues related to the Connecticut RMR agreement. We reached our maximum payment under that agreement during the first quarter of 2005.

Hedging and Risk Management Activity — The total derivative loss for the year was $283 million, comprised of $132 million in financial revenue losses and $151 million of mark-to-market losses. The $132 million loss of financial revenues represent the settled value for the year of all financial instruments including financial swaps and options on power. Of the $151 million of mark-to-market losses, $119 million represents fair value of forward sales of electricity and fuel — $121 million losses associated with electricity sales and $2 million gain associated with cost of fuel, the reversal of $59 million of mark-to-market gains which ultimately settled as financial revenues and $27 million mark-to-market gain related to trading activity. These activities primarily support our Northeast assets.

Since hedging activities are intended to mitigate the risk of commodity price movements on revenues and cost of energy sold, the changes in such results should not be viewed in isolation, but rather taken together with the effects of pricing and cost changes on energy revenues and costs of energy. In the fourth quarter of 2004 and over the course of 2005, we hedged much of our calendar year 2005 and 2006 Northeast generation. Since that time and during the third quarter 2005 in particular, the settled and forward prices of electricity rose, driven by the extreme weather conditions this summer. While this increase in electricity prices benefited our generation portfolio versus last year with higher energy revenues, it is also the reason for the mark-to-market recognition of the forward sales and the settlement of positions as losses.

Cost of energy

Cost of energy increased by $350 million for our Northeast region for the year ended December 31, 2005 compared to the same period in 2004. Oil fuel costs in our Northeast region increased by $162 million, where 65% of the increase was due to increased generation. The Northeast's gas fuel costs increased by $129 million. Higher gas sales from our New York City assets drove $15 million of the increase, with $109 million of the increase related to higher prices and demand for our NYC assets. Coal costs increased by $61 million, due to increased prices, although our coal-fired generation in the Northeast had a minimal decrease during 2005 as compared to 2004, specifically due to scheduled and unplanned outages at our western New York and Indian River facilities during the second and fourth quarters. Of the $61 million increase in coal cost, 71% was due to increases at our Indian River plant. Our Indian River plant uses a higher portion of eastern coal, whose price experienced a significant cost increase during 2005.

Other Operating Expenses

Other operating costs for our Northeast region increased by $55 million for the year ended December 31, 2005 compared to the same period in 2004. This increase was driven by operating and maintenance costs, led by higher major maintenance costs. The low-sulfur conversion projects continued at our Western New York plants and began at our Indian River plant this year and major outages related to turbine overhauls took place at our Western New York and Indian River plants. The increased number and extensiveness of the outages contributed to the $14 million increase in major maintenance expense this year. Additionally, in 2004, a settlement with a third party vendor regarding auxiliary power charges reduced 2004 operating and maintenance expenses by $7 million.

Other operating expenses for the Northeast region include the administrative regional office costs, other non-income tax expense, insurance and corporate allocations. These costs increased by $30 million in 2005 compared to 2004, $14 million of which was due in non-income tax expense as we recognized property tax credits in 2004. Additionally, regional office and corporate allocations also increased per our new allocation methodology as discussed in Item 15 — Note 21, *Segment Reporting*, to the Consolidated Financial Statements.

South Central Region Results

Operating Income

For the year ended December 31, 2005, the South Central region realized operating income of $20 million, as compared to $58 million for the year ended December 31, 2004. During 2005, our Big Cajun II facility experienced several forced outages during the summer months, at which time contract demand and replacement power costs were at their highest. Generation for 2005 decreased by 6% from 10.6 million MWh to 9.9 million MWh versus the same period in 2004, with 0.2 million MWh lost due to forced outages. These outages contributed to the purchase of $114 million in additional purchased energy required to meet contract load-following obligation in the merchant market at costs higher than our coal-based generating assets. In addition, during 2005, South Central had three planned outages versus one major planned outage during 2004, which increased major maintenance by $16 million as compared to the year ended December 31, 2004.

Revenues

Revenues from our South Central region were $552 million for the year ended December 31, 2005 compared to $418 million for the same period in 2004, an increase of $134 million. Revenues for the year ended December 31, 2005 included $330 million in energy revenues, of which 62% were contracted. This compares to $219 million of energy revenues for the year ended December 31, 2004, 73% of which were contracted. This increase of $111 million in energy revenues and the lower percentage contracted was due to increased merchant energy sales following higher power prices, favorable weather, and nuclear plant outages in the region. Also, a round-the-clock 100 MW sale to Entergy and a tolling agreement which at times provided power that could be resold at a higher price helped to boost merchant revenues. Other revenues include physical gas sales and Fresh Start-related contract amortization. For the year ended December 31, 2005, other revenues totaled $37 million compared to $16 million for the year ended December 31, 2004, with the increase due to $23 million increase in physical gas sales related to a new gas sale agreement entered into in July 2005. We entered into this agreement in conjunction with power purchase agreements to minimize our market purchases during peak months.

Cost of Energy

South Central's cost of energy increased by $145 million for the year ended December 31, 2005 compared to the same period in 2004. Of this amount, $114 million is due to higher purchased energy costs. During 2005, our Big Cajun II facility experienced a number of forced outages, encountered high demand from the Region's long-term contracts, and entered into 100-MW around-the-clock sale to Entergy, and a tolling agreement, all of which required the purchase of energy to meet contract load obligations. Purchased energy per MWh increased by 238% versus the same period in 2004. Additionally, due to the extreme weather conditions and increasing gas prices, the average purchased energy price increased $18.20 per MWh for the year ended December 31, 2005 as compared to the same period in 2004.

Other Operating Expenses

Other operating expenses increased by $33 million for the year ended December 31, 2005 compared to the same period in 2004, with $16 million of the increase related to increased planned and unplanned outages at our Big Cajun II facility, and $13 million related to regional office and the new NRG allocation methodology discussed in Item 15 — Note 21, *Segment Reporting*, to the Consolidated Financial Statements.

Western Region Results

For the year ended December 31, 2005, the Western region realized an operating loss of $6 million, as compared to an operating loss of $9 million for the same period in 2004, a reduction of $3 million in our loss. This reduction is due to the payment of CAISO penalties paid by our Red Bluff and Chowchilla facilities in 2004, offset by the expiration of the Red Bluff RMR contract as of December 31, 2004.

Other North America Region Results

For the year ended December 31, 2005, the Other North America region realized an operating loss of $28 million on revenues of $15 million, as compared to an operating loss of $5 million and revenues of $94 million for the year ended December 31, 2004. This unfavorable variance is primarily related to the sale of Kendall and the expiration of a tolling agreement at our Rockford facility. Both Kendall and Rockford had operating income of $3 million each, for the year ended December 31, 2004 and revenues of $73 million and $15 million, respectively. Other operating expenses and depreciation and amortization for our Other North America region for the year ended December 31, 2005 were $16 million and $7 million, respectively. For the year ended December 31, 2004, other operating expenses and depreciation and amortization were $42 million and $21 million, respectively. The favorable variance in both of these is due to the sale of Kendall.

Australia Region Results

Operating Income

For the year ended December 31, 2005, the Australia region realized an operating loss of $7 million, as compared to an operating loss of $5 million for the same period in 2004. Unseasonably mild weather and weak pool prices in the first quarter drove the unfavorable results as compared to last year. Higher generation for the year ended December 31, 2005 helped to offset weak pool prices, with generation increasing 6% over 2004.

Revenues

Revenues from our Australia region totaled $212 million for the year ended December 31, 2005 compared to $181 million for the year ended December 31, 2004, an increase of approximately $31 million, with $7 million as a result of the strengthening Australian dollar in 2005. Energy revenues decreased by $15 million primarily due to the weak pool prices experienced in the first quarter of the year. An unseasonably mild summer in Australia drove the average annualized pool price down to $23 per MWh from $30 per MWh in 2004, a reduction of 26%. This decrease was offset by $18 million of financial revenues, representing the settled value of financial instruments, including financial swaps on power, and $10 million of higher derivative revenues, representing the change in fair value of forward sales of electricity and fuel. Additionally, 5% higher generation due to fewer planned outage hours at the Osborne Power Station in 2005 and the full commercialization of the Playford station during the fourth quarter of 2004, helped to offset the impact of the lower pool prices. For the year ended December 31, 2005, other revenues totaled $25 million compared to $7 million of other revenues for the same period in 2004. Other revenues were favorably impacted by lower contract amortization of $15 million in 2005 as a significant contract was canceled in 2004.

Cost of Energy

Fuel costs increased by $14 million, with $10 million of this related to an 18% increase in purchased power from Osborne Power Station in 2005 and $3 million due to additional gas expenses to support these higher generation levels. These increased costs are offset by increased revenue from merchant electricity and gas sales in 2005 related to our Osborne plant. Fuel oil costs in 2005 were approximately $1 million higher due to a combination of increased world oil prices and increased starts at Playford.

Other Operating Expenses

Other operating expenses for Australia for the year ended December 31, 2005 increased by $16 million over the same period in 2004. Operating and maintenance expense increased by $10 million in 2005 with $3 million attributable to the strengthening Australian dollar. Increased operational and maintenance costs relating to our Playford power station in addition to higher coal production costs to support the higher generation levels led to a further $2 million increase. Significant increases in world oil prices over the 2005 year resulted in $1 million of additional costs related to coal mining and delivery. Labor costs at Flinders were up approximately $1 million, a combination of increasing provision levels for workers compensation claims and increased charges relating to pension charges. Additionally, due to the new NRG allocations methodology as discussed in Item 15 — Note 21, *Segment Reporting,* to the Consolidated Financial Statements, the Australia region incurred $6 million in higher corporate allocations as compared to 2004.

For the Year Ended December 31, 2004 Compared to the Year Ended December 31, 2003

Net Income

Reorganized NRG

For the year ended December 31, 2004, we recorded net income of $186 million, or $1.85 per weighted average share of diluted common stock. These favorable results occurred despite a challenging market environment in 2004. Unseasonably mild weather, high volatility on forward markets and disappointing spot power prices summarize 2004's events. The NOAA has ranked the mean average temperatures over the past 110 years by season for each of the lower 48 states. The year 2004 started with the winter being colder than normal in the east coast followed by a spring, summer and fall which were among the mildest in the last 110 years throughout most of the United States. Although mild weather in the North America market kept spot market on-peak power prices were low throughout most of the year, relatively high gas and oil prices kept spark spreads on coal-based assets positive.

The overall perception that there would be significant production losses due to Hurricane Ivan ignited a strong pre-heating season rally in natural gas futures during the early fourth quarter. While power prices tracked changes in natural gas prices, this movement was not one for one. As a result, our spark spreads on coal-based generation increased dramatically with the fall 2004 changes in gas prices. During this period we sold forward 2005 power locking in these spark spreads. Forward power prices have fallen considerably from the highs set in October, and many of those forward sales, which were marked-to-market through earnings, significantly contributed to the $57 million unrealized gain recorded in revenue for the year ended December 31, 2004 and as more fully described in Item 15 — Note 15 to the Consolidated Financial Statements. The majority of the unrealized gains relate to forward sales of electricity which were realized in 2005. These gains were offset by our South Central region's results, which were negatively impacted by an unplanned outage in the fourth quarter forcing us to purchase power to meet our contract supply obligations. Our results were also favorably impacted by the FERC-approved settlement agreement between NRG Energy and Connecticut Light & Power, or CL&P, and others concerning the congestion and losses obligation associated with a prior standard offer service contract, whereby we received $38 million in settlement proceeds in July 2004. The 2004 results were also positively impacted by $160 million in equity earnings of unconsolidated affiliates including $69 million from our interest in West Coast Power which benefited from warmer than normal temperatures during the year. Impairment charges of $45 million negatively impacted net income; of which $27 million relates to the Kendall asset.

During the period December 6, 2003 through December 31, 2003, we recognized net income of $11 million or $0.11 per share of common stock. From an overall operational perspective our facilities were profitable during this period. Our results were adversely impacted by our having to continue to satisfy the standard offer service contract that we entered into with CL&P in 2000. As a result of our inability to terminate this contract during our bankruptcy proceeding, we continued to be exposed to losses under this contract. These losses were incurred, as we were unable to satisfy the requirements of this contract at a price/cost below the contracted sales price. Upon our adoption of Fresh Start, we recorded at fair value, all assets and liabilities on our opening balance sheet and accordingly we recorded as an obligation the fair value of the CL&P contract. During the period December 6, 2003 through December 31, 2003, we recognized as revenues the entire fair value of this contract effectively offsetting the actual losses incurred under this contract. The CL&P contract terminated on December 31, 2003.

Predecessor Company

During the period January 1, 2003 through December 5, 2003, we recorded net income of $2.8 billion. Net income for the period is directly attributable to our emerging from bankruptcy and adopting the Fresh

Start provisions of SOP 90-7. Upon the confirmation of our Plan of Reorganization and our emergence from bankruptcy, we were able to remove significant amounts of long-term debt and other pre-petition obligations from our balance sheet. Accordingly, as part of net income, we recorded a net gain of $3.9 billion (comprised of a $4.2 billion gain from continuing operations and a $0.3 billion loss from discontinued operations) as the impact of our adopting Fresh Start in our statement of operations. $6 billion of this amount is directly related to the forgiveness of debt and settlement of substantial amounts of our pre-petition obligations upon our emergence from bankruptcy. In addition to the removal of substantial amounts of pre-petition debt and other obligations from our balance sheet, we also revalued our assets and liabilities to fair value. Accordingly, we substantially wrote down the value of our fixed assets. We recorded a net $1.6 billion charge related to the revaluation of our assets and liabilities within the Fresh Start Reporting adjustment line of our consolidated statement of operations. In addition to our adjustments related to our emergence from bankruptcy, we also recorded substantial charges related to other items such as the settlement of certain outstanding litigation in the amount of $463 million, write downs and losses on the sale of equity investments of $147 million, advisor costs and legal fees directly attributable to our being in bankruptcy of $198 million and $237 million of other asset impairment and restructuring costs incurred prior to our filing for bankruptcy. Net income for the period January 1, 2003 through December 5, 2003 was favorably impacted by our not recording interest expense on substantial amounts of corporate level debt while we were in bankruptcy and by the continued favorable results experienced by our equity investments.

Revenues from Majority-Owned Operations

Reorganized NRG

Our revenues from majority-owned operations were $2.3 billion for the year ended December 31, 2004 which included $1.4 billion of energy revenues, $612 million of capacity revenues, $175 million of alternative energy revenues, $21 million of O&M fees, $76 million of hedging and risk management activities and $99 million other revenues.

Revenues from majority-owned operations for the year ended December 31, 2004, were driven primarily by our North American operations, primarily our Northeast facilities. Our wholly-owned North America assets generated approximately 29 million MWh during the year 2004 with the Northeast region representing 46% of these MWh's. Of the total $1.4 billion in energy revenues, the Northeast region represented 62%. Our energy revenues were favorably impacted by the FERC-approved settlement agreement between us and CL&P and others, whereby we received $38 million in settlement proceeds in July 2004. These settlement proceeds are included in the All Other segment in the energy revenue category. South Central's energy revenues are driven by our ability to sell merchant energy, which is dependent upon available generation from our coal-based Louisiana Generating company after serving our co-op customer and long-term customer load obligations. Since our load obligation is primarily residential load, our merchant opportunities are largely available in the off-peak hours of the day. Our Australian operations were favorably impacted by strong market prices driven by gas restrictions in January, record high temperatures in February and March, and favorable foreign exchange movements. Our capacity revenues are largely driven by our Northeast and South Central facilities. Our South Central and New York City assets earned 30% and 26% of our total capacity revenues, respectively. In the Northeast, our Connecticut facilities continue to benefit from the cost-based reliability must-run, or RMR agreements, which were authorized by FERC as of January 17, 2004 and approved by FERC on January 27, 2005. The agreements entitle us to approximately $7 million of capacity revenues per month until January 1, 2006, the LICAP implementation date. In the South Central region, our long-term contracts provide for capacity payments. Other North American capacity revenues were generated by our Kendall operation, which had a long-term tolling agreement. During this period we also experienced a favorable impact on our revenues due to the mark-to-market on certain of our derivative contracts wherein we have recognized $57 million in unrealized gains. This gain is related to our Northeast assets and is included in the hedging and risk management activities. Included in Other Revenue in the Northeast are the cost reimbursement funds under the RMR agreement for our Connecticut assets. Our revenues during this period include net charges of $35 million of non-cash amortization of the fair values of various executory contracts recorded on our balance sheet upon our adoption of the Fresh Start provisions of SOP 90-7 in December 2003.

Our revenues from majority-owned operations were $137 million for the period December 6, 2003 through December 31, 2003.

Predecessor Company

Revenues from majority-owned operations were $1.8 billion for the period January 1, 2003 through December 5, 2003 and include approximately $910 million of energy revenues, $566 million of capacity revenues, $82 million of alternative energy, $13 million of O&M fees, $19 million of hedging and risk management activities and $208 million other revenues. Revenues from majority-owned operations during the period ended December 5, 2003, were driven primarily by our North American operations and to a lesser degree by our international operations, primarily Australia. Our domestic Northeast and South Central power generation operations significantly contributed to our revenues due primarily to favorable market prices resulting from strong fuel and electricity prices. Our Australian operations were favorably impacted by foreign exchange rates. During this period we also experienced an unfavorable impact on our revenues due to continued losses on our CL&P standard offer contract and the mark-to-market on certain of our derivatives.

Cost of Majority-Owned Operations

Our cost of majority-owned operations for the year ended December 31, 2004 was $1.5 billion or 63% of revenues from majority-owned operations. Cost of majority-owned operations consist of $1.006 billion of cost of energy (primarily fuel and purchased energy costs), or 43% of revenues from majority-owned operations and $483 million of operating expenses, or 21% of revenues from majority-owned operations. Operating expenses consist of $207 million of labor related costs, $235 million of operating and maintenance costs, $38 million of non-income based taxes and $3 million of asset retirement obligation accretion.

Cost of Energy

Fuel related costs include $476 million in coal costs, $233 million in natural gas costs, $105 million in fuel oil costs, $39 million in transmission and transportation expenses, $100 million of purchased energy costs, $35 million in other costs and $18 million in non-cash SO_2 emission credit amortization resulting from Fresh Start accounting. The Northeast region consumed 50%, 64% and 91% of total coal, natural gas and oil expenditures, respectively. The South Central region, which is comprised mainly of our Louisiana base-loaded coal plant, consumed 32% of our total coal expenditures.

Operating Expenses

Reorganized NRG

Operating expenses related to continuing operations for the year ended December 31, 2004 were $483 million or 21% of revenues from majority-owned operations. Operating expenses include labor, normal and major maintenance costs, environmental and safety costs, utilities costs, and non-income based taxes. Labor costs include regular, overtime and contract costs at our plants and totaled $207 million. The Northeast region, where the majority of our assets reside, represents 53% of total labor costs; Australia represents 18%, while our South Central region represents 12%. Of the total O&M costs, normal and major maintenance at our plants accounted for $176 million, or 36% of total operating costs. Maintenance costs were largely driven by planned outages across our fleet, and the low-sulfur coal conversion in western New York. The Northeast region represented over half of the normal and major maintenance, with a total of $99 million in costs in 2004 while Australia had $40 million in normal and major maintenance, or 23%. Operating expenses were positively impacted by a $7 million favorable settlement with a vendor regarding auxiliary power charges. Non-income based taxes totaled $38 million net of $35 million in property tax credits, primarily associated with an enterprise zone program.

Cost of majority-owned operations was $95 million, or 69% of revenues from majority-owned operations for the period December 6, 2003 through December 31, 2003. Cost of energy for this period was $63 million or 46% of revenues from majority-owned operations and operating expenses were $32 million, or 23% of revenues from majority-owned operations. Labor during this period totaled $11 million. Normal and major maintenance was $12 million with 67% of the total normal and major maintenance for this time period coming from our Northeast region.

Predecessor Company

Cost of majority-owned operations was $1.4 billion, or 75% of revenues from majority-owned operations for the period January 1, 2003 through December 5, 2003. Cost of majority-owned operations was unfavorably impacted by increased generation in the Northeast region, partially offset by a reduction in trading and hedging activity resulting from a reduction in our power marketing activities. Our international operations were impacted by an unfavorable movement in foreign exchange rates and continued mark-to-market of the Osborne contract at Flinders resulting from lower pool prices.

Depreciation and Amortization

Reorganized NRG

Our depreciation and amortization expense related to continuing operations for the year ended December 31, 2004 was $208 million. Depreciation and amortization consists primarily of the allocation of our historical depreciable fixed asset costs over the remaining lives of such property. Upon adoption of Fresh Start, we were required to revalue our fixed assets to fair value and determine new remaining lives for such assets. Our fixed assets were written down substantially upon our emergence from bankruptcy. We also determined new remaining depreciable lives, which are, on average, shorter than what we had previously used primarily due to the age and condition of our fixed assets.

Depreciation and amortization expense for the period December 6, 2003 through December 31, 2003 was $12 million. Depreciation and amortization expense consists of the allocation of our newly valued basis in our fixed assets over newly determined remaining fixed asset lives.

Predecessor Company

Our depreciation and amortization expense related to continuing operations for the period January 1, 2003 through December 5, 2003 was $211 million. During this period, depreciation expense was unfavorably impacted by the shortening of the depreciable lives of certain of our domestic power generation facilities located in the Northeast region and the impact of recently completed construction projects. The depreciable lives of certain of our Northeast facilities, primarily our Connecticut facilities, were shortened to reflect economic developments in that region. Certain capitalized development costs were written-off in connection with the Loy Yang project resulting in increased expense. Amortization expense increased due to reducing the life of certain software costs.

General, Administrative and Development

Reorganized NRG

Our general, administrative and development costs related to continuing operations for the year ended December 31, 2004 were $210 million. Of this total, $111 million or 5% of revenues from majority-owned operations represents our corporate costs, with the remaining $99 million representing costs at our plant operations. Corporate costs are primarily comprised of corporate labor, external professional support, such as legal, accounting and audit fees, and office expenses. Corporate general, administrative and development expenses were negatively impacted this year by increased legal fees, increased audit costs and increased consulting costs due to our Sarbanes Oxley testing and implementation. Plant general, administrative and development costs primarily include insurance and external consulting costs. Plant insurance costs were $41 million. Additionally, we recorded $12 million in bad debt expense related to notes receivable.

General, administrative and development costs were $13 million, or 10% of revenues from continuing operations for the period December 6, 2003 to December 31, 2003. These costs are primarily comprised of corporate labor, insurance and external professional support, such as legal, accounting and audit fees.

Predecessor Company

Our general, administrative and development costs related to continuing operations for the period January 1, 2003 to December 5, 2003 were $170 million or 10% of revenues from majority-owned operations. These costs are primarily comprised of corporate labor, insurance and external professional support, such as legal, accounting and audit fees.

Other Charges (Credits)

Reorganized NRG

For the year ended December 31, 2004, we recorded other charges of $48 million, which consisted of $16 million of corporate relocation charges, $13 million of reorganization credits and $45 million of restructuring and impairment charges.

For the period December 6, 2003 through December 31, 2003 we recorded $2 million of reorganization charges.

Predecessor Company

During the period January 1, 2003 to December 5, 2003, we recorded other credits of $3.3 billion, which consisted primarily of $229 million related to asset impairments, $463 million related to legal settlements, $198 million related to reorganization charges and $8 million related to restructuring charges. We also incurred a $4.2 billion credit related to Fresh Start adjustments.

Other charges (credits) consist of the following:

	Reorganized NRG		Predecessor Company
	Year Ended December 31, 2004	For the Period December 6 - December 31, 2003	For the Period January 1 - December 5, 2003
		(In millions)	
Corporate relocation charges	$ 16	$ —	$ —
Reorganization items	(13)	2	198
Impairment charges	45	—	229
Restructuring charges	—	—	8
Fresh Start adjustments	—	—	(4,220)
Legal settlement	—	—	463
Total	$ 48	$ 2	$ (3,322)

Corporate Relocation Charges

On March 16, 2004, we announced plans to implement a new regional business strategy and structure. The new structure called for a reorganized leadership team and a corporate headquarters relocation to Princeton, New Jersey. The corporate headquarters staff were streamlined as part of the relocation, as functions were either reduced or shifted to the regions. As of December 31, 2005, the transition of the corporate headquarters is complete. During the year ended December 31, 2004, we recorded $16 million for charges related to our corporate relocation activities, primarily for employee severance and termination benefits and employee related transition costs. These charges are classified separately in our statement of operations, in accordance with SFAS No. 146, *"Accounting for Costs Associated with Exit or Disposal Activities"*. See Item 15 — Note 8 to our consolidated financial statements for more information.

Costs not classified separately as relocation charges include rent expense of our temporary office in Princeton, construction costs of our new office and certain labor costs. All costs relating to the corporate relocation that are not classified separately as relocation charges, except for approximately $6 million of related capital expenditures will be expensed as incurred and included in general, administrative and development expenses. Cash expenditures for 2004, including capital expenditures, were $22 million.

We recognized a curtailment gain of approximately $1 million on our defined benefit pension plan in the fourth quarter of 2004, as a substantial number of our current headquarters staff left the Company in this period.

Reorganization Items

For the year ended December 31, 2004, we recorded a net credit of $13 million related primarily to the settlement of obligations recorded under Fresh Start. We incurred $7 million of professional fees associated with the bankruptcy which offset $20 million of credits associated with creditor settlements. For the periods December 6, 2003 to December 31, 2003 and January 1, 2003 to December 5, 2003, we incurred $2 million and $198 million, respectively, in reorganization costs. All reorganization costs have been incurred since we filed for bankruptcy in May 2003. Also see Item 15 — Note 8 for a tabular description of expenses.

Impairment Charges

We review the recoverability of our long-lived assets in accordance with the guidelines of SFAS No. 144. As a result of this review, we recorded impairment charges of $45 million and $229 million for the year ended December 31, 2004 and the period January 1, 2003 through December 5, 2003, respectively, as shown in the table below. Of the $45 million total in 2004, Kendall and the Meriden turbine accounted for $27 million and $15 million, respectively. We successfully completed the sale of Kendall in November 2004 and expect to complete the sale of the Meriden turbines in 2006. There were no impairment charges for the period December 6, 2003 through December 31, 2003.

To determine whether an asset was impaired, we compared asset-carrying values to total future estimated undiscounted cash flows. If an asset was determined to be impaired based on the cash flow testing performed, an impairment loss was recorded to write down the asset to its fair value.

See Item 15 — Note 8 for a list of impairment charges (credits) for the year ended December 31, 2004 and the period January 1, 2003 to December 5, 2003.

Restructuring Charges

We incurred $8 million of employee separation costs and advisor fees during the period January 1, 2003 until we filed for bankruptcy in May 2003. Subsequent to that date we recorded all advisor fees as reorganization costs.

Fresh Start Adjustments

During the fourth quarter of 2003, we recorded a net credit of $3.9 billion (comprised of a $4.2 billion gain from continuing operations and a $0.3 billion loss from discontinued operations) in connection with fresh start adjustments. Following is a summary of the significant effects of the reorganization and Fresh Start:

	(In millions)
Discharge of corporate level debt	$ 5,162
Discharge of other liabilities	811
Establishment of creditor pool	(1,040)
Receivable from Xcel	640
Revaluation of fixed assets	(1,392)
Revaluation of equity investments	(207)
Valuation of SO_2 emission credits	374
Valuation of out of market contracts, net	(400)
Fair market valuation of debt	108
Valuation of pension liabilities	(61)
Other valuation adjustments	(100)
Total Fresh Start adjustments	3,895
Less discontinued operations	(325)
Total Fresh Start adjustments — continuing operations	$ 4,220

Legal Settlement Charges

During the period January 1, 2003 to December 5, 2003, we recorded $463 million of legal settlement charges which consisted of the following. We recorded $396 million in connection with the resolution of an arbitration claim asserted by FirstEnergy Corp. As a result of this resolution, FirstEnergy retained ownership of the Lake Plant Assets and received an allowed general unsecured claim of $396 million under NRG Energy's Plan of Reorganization. In November 2003, we settled litigation with Fortistar Capital in which Fortistar Capital released us from all litigation claims in exchange for a $60 million pre-petition bankruptcy claim and an $8 million post-petition bankruptcy claim. We had previously recorded approximately $11 million in connection with various legal disputes with Fortistar Capital; accordingly, we recorded an additional $57 million during November 2003. In November 2003, we settled our dispute with Dick Corporation in connection with Meriden Gas Turbines LLC through the payment of a general unsecured claim and a post-petition pre-confirmation payment. This settlement resulted in our recording an additional liability of $8 million in November 2003.

In August 1995, we entered into a Marketing, Development and Joint Proposing Agreement, or the Marketing Agreement, with Cambrian Energy Development LLC, or Cambrian. Various claims arose in connection with the Marketing Agreement. In November 2003, we entered into a settlement agreement with Cambrian where we agreed to transfer our 100% interest in three gasco projects (NEO Ft. Smith, NEO Phoenix and NEO Woodville) and our 50% interest in two genco projects (MM Phoenix and MM Woodville) to Cambrian. In addition, we paid approximately $2 million in settlement of royalties incurred in connection with the Marketing Agreement. We had previously recorded a liability for royalties owed to Cambrian, therefore, we recorded an additional $1 million during November 2003.

Other Income (Expense)

Reorganized NRG

During the year ended December 31, 2004, we recorded other expense of $167 million. Other expense consisted primarily of $266 million of interest expense, $72 million of refinancing-related expenses, $16 million of write downs and losses on sales of equity method investments, offset by $160 million of equity in earnings of unconsolidated affiliates (including $69 million from our investment in West Coast Power LLC) and $27 million of other income, net.

Other income (expense) for the period December 6, 2003 through December 31, 2003, was an expense of $5 million and consisted primarily of $19 million of interest expense, partially offset by $14 million of equity in earnings of unconsolidated affiliates.

Predecessor Company

During the period January 1, 2003 through December 5, 2003, we recorded other expense of $265 million. Other expense consisted primarily of $308 million of interest expense and $147 million of write downs and losses on sales of equity method investments, partially offset by equity in earnings of unconsolidated affiliates of $171 million and $19 million of other income, net.

Equity in Earnings of Unconsolidated Affiliates

Reorganized NRG

For the year ended December 31, 2004, we recorded $160 million of equity earnings from our investments in unconsolidated affiliates. Our equity in earnings of WCP comprised $69 million of this amount with our equity in earnings of Enfield, MIBRAG, and Gladstone comprising $28 million, $21 million, and $17 million, respectively. Our investment in WCP generated favorable results due to the pricing under the CDWR contract. Additionally, revenues from ancillary services revenue and minimum load cost compensation power positively contributed to WCP's operating results. However, our equity earnings in the project as reported in our results of operations have been reduced by a net $116 million to reflect a non-cash basis adjustment for in the money contracts resulting from adoption of Fresh Start.

NRG Energy's equity earnings were also favorably impacted by $23 million of unrealized gain related to our Enfield investment. This gain is associated with changes in the fair value of energy-related derivative instruments not accounted for as hedges in accordance with SFAS No. 133.

Equity in earnings of unconsolidated affiliates of $14 million for the period December 6, 2003 through December 31, 2003 consists primarily of equity earnings from our 50% ownership in WCP of $9 million.

Predecessor Company

During the period January 1, 2003 through December 5, 2003, we recorded $171 million of equity earnings from investments in unconsolidated affiliates. Our 50% investment in WCP comprised $99 million of this amount with our investments in the MIBRAG, Loy Yang, Gladstone and Rocky Road projects comprising $22 million, $18 million, $12 million and $7 million, respectively, with the remaining amounts attributable to various domestic and international equity investments.

Equity in earnings of unconsolidated affiliates consists of the following:

	Reorganized NRG		Predecessor Company
	Year Ended December 31, 2004	December 6, 2003 Through December 31, 2003	January 1, 2003 Through December 5, 2003
		(In millions)	
WCP	$ 69	$ 9	$ 99
MIBRAG	21	—	22
Enfield	28	1	6
Gladstone	17	1	12
Rocky Road	7	—	7
James River	8	1	(2)
NRG Saguaro	5	1	4
Scudder LA Trust	2	—	3
NRG National	1	—	2
Loy Yang	—	—	18
Other	2	1	—
Total Equity in Earnings of Unconsolidated Affiliates	$ 160	$ 14	$ 171

Write Downs and Losses on Sales of Equity Method Investments

As part of our periodic review of our equity method investments for impairments, we have taken write downs and losses on sales of equity method investments during the year ended December 31, 2004 of $16 million and $147 million for the period January 1, 2003 through December 5, 2003. Our Commonwealth Atlantic Limited Partnership (CALP) and James River investments were written down based on indicative market bids. The sale of CALP closed in the fourth quarter of 2004, while the sale agreement for James River has been terminated. There were no write downs and losses on sales of equity method investments for the period December 6, 2003 through December 31, 2003.

Further details as to write downs and losses (gains) on sales of equity method investments recorded in the consolidated statement of operations are detailed in Item 15 — Note 7 to the Consolidated Financial Statements.

Other Income, net

Reorganized NRG

During the year ended December 31, 2004, we recorded $27 million of other income, net, consisting primarily of interest income earned on notes receivable and cash balances. For the period December 6, 2003 through December 31, 2003 we recorded an immaterial amount of other income.

Predecessor Company

During the period January 1, 2003 through December 5, 2003, we recorded $19 million of other income, net. During this period other income, net consisted primarily of interest income earned on notes receivable and cash balances, offset in part by the unfavorable mark-to-market on our corporate level £160 million note that was cancelled in connection with our bankruptcy proceedings.

Interest Expense

Reorganized NRG

Interest expense for the year ended December 31, 2004 was $266 million, consisting of interest expense on both our project- and corporate-level interest-bearing debt. Significant amounts of our corporate-level debt were forgiven upon our emergence from bankruptcy and we refinanced significant amounts of our project-level debt with corporate level high yield notes and term loans in December 2003. Also included in interest expense is the amortization of debt financing costs of $9 million related to our corporate level debt and $13 million of amortization expense related primarily to debt discounts and premiums recorded as part of Fresh Start. Interest expense also includes the impact of any interest rate swaps that we have entered in order to manage our exposure to changes in interest rates.

Interest expense for the period December 6, 2003 through December 31, 2003 of $19 million consists primarily of interest expense at the corporate level, primarily related to the Second Priority Notes, term loan facility and revolving line of credit used to refinance certain project-level financings. In addition, interest expense includes the amortization of deferred financing costs incurred as a result of our refinancing efforts and the amortization of discounts and premiums recorded upon the marking of our debt to fair value upon our adoption of the Fresh Start provision of SOP 90-7.

Predecessor Company

Interest expense for the period January 1, 2003 through December 5, 2003 of $308 million consisted of interest expense on both our project and corporate level interest bearing debt. In addition, interest expense includes the amortization of debt issuance costs and any interest rate swap termination costs. Interest expense during this period was favorably impacted by our ceasing to record interest expense on debt where it was probable that such interest would not be paid, such as the NRG Energy corporate level debt (primarily bonds) and the NRG Finance Company debt (construction revolver) due to our entering into bankruptcy in May 2003. We did not however cease to record interest expense on the project-level debt outstanding at our Northeast Generating and South Central Generating facilities even though these entities were also in bankruptcy as these claims were deemed to be most likely not impaired and not subject to compromise. We also recorded substantial amounts of fees and costs related to our acquiring a debtor in possession financing arrangement while we were in bankruptcy. In addition, upon our emergence from bankruptcy we wrote off any remaining deferred finance costs related to our corporate and project-level debt including our Northeast and South Central project-level debt as it was probable that they would be refinanced upon our emergence from bankruptcy. Interest expense was unfavorably impacted by an adverse mark-to-market on certain interest rate swaps that we have entered in order to manage our exposure to changes in interest rates. Due to our deteriorating financial condition during such period, hedge accounting treatment was ceased for certain of our interest rate swaps, causing changes in fair value to be recorded as interest expense.

Refinancing Expense

Refinancing expense was $72 million for the year ended December 31, 2004. This amount includes $15 million of prepayment penalties and a $15 million write-off of deferred financing costs related to refinancing certain amounts of our term loans with additional corporate level high yield notes in January 2004 and $14 million of prepayment penalties and a $27 million write-off of deferred financing costs related to refinancing the senior credit facility in December 2004.

Income Tax Expense

Reorganized NRG

Our income tax provision from continuing operations was $65 million for the year ended December 31, 2004 and an income tax benefit of ($1) million for the period December 6, 2003 through December 31, 2003. The overall effective tax rate in 2004 and the short period in 2003 was 28.7% and (6.2%), respectively. The change in our effective tax rate was primarily due to a state tax refund received from Xcel Energy in 2003 and foreign income taxed in jurisdictions with tax rates different from the U.S. statutory rate.

Our net deferred tax assets at December 31, 2004 were offset by a full valuation allowance in accordance with SFAS No. 109. Under SOP 90-7, any future benefits from reducing a valuation allowance from pre-confirmation deferred tax assets are required to be reported first as an adjustment of identifiable intangible assets and then as a direct addition to paid in capital versus a benefit on our statement of operations.

The effective tax rate may vary from year to year depending on, among other factors, the geographic and business mix of earnings and losses. These same and other factors, including history of pre-tax earnings and losses, are taken into account in assessing the ability to realize deferred tax assets.

Predecessor Company

Income tax expense for the period January 1, 2003 through December 5, 2003 was $38 million. The overall effective tax rate for the period ended December 5, 2003 was 1.3%. The rate is lower than the U.S. statutory rate primarily due to a release in valuation allowance for net operating loss carryforwards that were utilized following our emergence from bankruptcy to offset the current tax on cancellation of debt income.

Income taxes have been recorded on the basis that our U.S. subsidiaries and we would file separate federal income tax returns for the period January 1, 2003 through December 5, 2003. Since our U.S. subsidiaries and we were not included in the Xcel Energy consolidated tax group, each of our U.S. subsidiaries that is classified as a corporation for U.S. income tax purposes filed a separate federal income tax return. It is uncertain if, on a stand-alone basis, we would be able to fully realize deferred tax assets related to net operating losses and other temporary differences, therefore a full valuation allowance has been established.

Income From Discontinued Operations, net of Income Taxes

Reorganized NRG

We classified as discontinued operations the operations and gains/losses recognized on the sale of projects that were sold or were deemed to have met the required criteria for such classification pending final disposition. During the year ended December 31, 2004, we recorded income from discontinued operations, net of income taxes, of approximately $25 million. During the year ended December 31, 2004 and for the period December 6, 2003 to December 31, 2003, discontinued operations consisted of the results of our NRG McClain LLC, Penobscot Energy Recovery Company, or PERC, Compania Boliviana De Energia Electrica S.A. Bolivian Power Company Limited, or Cobee, Hsin Yu, LSP Energy (Batesville), four NEO Corporation projects (NEO Nashville LLC, NEO Hackensack LLC, NEO Prima Deshecha LLC and NEO Tajiguas LLC), Northbrook New York LLC, Northbrook Energy LLC and Audrain Generating LLC. All other discontinued operations were disposed of in prior periods. The $25 million income from discontinued operations includes a gain of $22 million, net of income taxes of $8 million, related primarily to the dispositions of Batesville, Cobee and Hsin Yu.

Discontinued operations for the period December 6, 2003 through December 31, 2003 is comprised of a loss of less than a million dollars attributable to the on going operations of our McClain, PERC, Cobee, LSP Energy, Hsin Yu, four NEO Corporation projects (NEO Nashville LLC, NEO Hackensack LLC, NEO Prima Deshecha LLC and NEO Tajiguas LLC) and Audrain Generating LLC. The financial results of Northbrook New York LLC and Northbrook Energy LLC have not been reclassified as discontinued operations in the consolidated statement of operations and the consolidated statement of cash flows, for the period December 6, 2003 through December 31, 2003 due to immateriality.

Predecessor Company

As of December 5, 2003, we classified as discontinued operations the operations and gains/losses recognized on the sales of projects that were sold or were deemed to have met the required criteria for such classification pending final disposition. For the period January 1, 2003 through December 5, 2003, discontinued operations consist of the historical operations and net gains/losses related to our Killingholme, McClain, PERC, Cobee, NEO Landfill Gas, Inc., or NLGI, seven NEO Corporation projects (NEO Nashville LLC, NEO Hackensack LLC, NEO Prima Deshecha LLC, NEO Tajiguas LLC, NEO Ft. Smith LLC, NEO Woodville LLC and NEO Phoenix LLC), Timber Energy Resources, Inc., or TERI, Cahua, Energia Pacasmayo, LSP Energy, Hsin Yu projects and Audrain Generating LLC. Prior to December 6, 2003, Northbrook New York LLC and Northbrook NewYork LLC were unconsolidated affiliates because the ownership structure prevented us from exercising a controlling influence over operating and financial policies of the projects.

For the period January 1, 2003 through December 5, 2003, the results of operations related to such discontinued operations was a net loss of $316 million due to a net loss of results of operations from discontinued operations of Audrain Generating LLC of $133 million, loss on the sale of our Peru projects, impairment charges of $101 million and $24 million, respectively, recorded at McClain and NLGI and fresh start adjustments at LSP Energy.

Reorganization and Emergence from Bankruptcy

On May 14, 2003, we and 25 of our U.S. affiliates, filed voluntary petitions for reorganization under Chapter 11 of the United States Bankruptcy Code, or the Bankruptcy Code, in the United States Bankruptcy Court for the Southern District of New York, or the bankruptcy court.

On May 15, 2003, NRG Energy, PMI, NRG Finance Company I LLC, NRGenerating Holdings (No. 23) B.V. and NRG Capital LLC filed the NRG plan of reorganization. On November 24, 2003, the bankruptcy court issued an order confirming the NRG plan of reorganization, and the plan became effective on December 5, 2003. On September 17, 2003, we filed the Northeast/South Central plan of reorganization in connection with our Northeast and South Central subsidiaries in Chapter 11. On November 25, 2003, the bankruptcy court issued an order confirming the Northeast/South Central plan of reorganization and the plan became effective on December 23, 2003.

Financial Reporting by Entities in Reorganization under the Bankruptcy Code and Fresh Start

Between May 14, 2003 and December 5, 2003, we operated as a debtor-in-possession under the supervision of the bankruptcy court. Our financial statements for reporting periods within that timeframe were prepared in accordance with the provisions of SOP 90-7.

For financial reporting purposes, the close of business on December 5, 2003, represents the date of emergence from bankruptcy. As used herein, the following terms refer to the Company and its operations:

"Predecessor Company"	The Company, pre-emergence from bankruptcy The Company's operations prior to December 6, 2003
"Reorganized NRG"	The Company, post-emergence from bankruptcy The Company's operations from December 6, 2003- December 31, 2004

The implementation of the NRG plan of reorganization resulted in, among other things, a new capital structure, the satisfaction or disposition of various types of claims against the Predecessor Company, the assumption or rejection of certain contracts, and the establishment of a new board of directors.

In connection with the emergence from bankruptcy, we adopted Fresh Start in accordance with the requirements of SOP 90-7. The application of SOP 90-7 resulted in the creation of a new reporting entity. Under Fresh Start, the enterprise value of our company was allocated among our assets and liabilities on a basis substantially consistent with purchase accounting in accordance with SFAS 141. Accordingly, we pushed down the effects of this allocation to all of our subsidiaries.

Under the requirements of Fresh Start, we have adjusted our assets and liabilities, other than deferred income taxes, to their estimated fair values as of December 5, 2003. As a result of marking our assets and liabilities to their estimated fair values, we determined that there was no excess reorganization value that was reallocated back to our tangible and intangible assets. Deferred taxes were determined in accordance with SFAS 109. The net effect of all Fresh Start adjustments resulted in a gain of $3.9 billion (comprised of a $4.2 billion gain from continuing operations and a $0.3 billion loss from discontinued operations), which is reflected in the Predecessor Company's results of operations for the period January 1, 2003 through December 5, 2003. The application of the Fresh Start provisions of SOP 90-7 created a new reporting entity having no retained earnings or accumulated deficit.

As part of the bankruptcy process we engaged an independent financial advisor to assist in the determination of our reorganized enterprise value. The fair value calculation was based on management's forecast of expected cash flows from our core assets. Management's forecast incorporated forward commodity market prices obtained from a third party consulting firm. A discounted cash flow calculation was used to develop the enterprise value of Reorganized NRG, determined in part by calculating the weighted average cost of capital of the Reorganized NRG. The Discounted Cash Flow, or DCF, valuation methodology equates the value of an asset or business to the present value of expected future economic benefits to be generated by that asset or business. The DCF methodology is a "forward looking" approach that discounts expected future economic benefits by a theoretical or observed discount rate. The independent financial advisors prepared a 30-year cash flow forecast using a discount rate of approximately 11%. The resulting reorganization enterprise value as included in the Disclosure Statement ranged from $5.5 billion to $5.7 billion. The independent financial advisor then subtracted our project-level debt and made several other adjustments to reflect the values of assets held for sale, excess cash and collateral requirements to estimate a range of Reorganized NRG equity value of between $2.2 billion and $2.6 billion.

In constructing our Fresh Start balance sheet upon our emergence from bankruptcy, we used a reorganization equity value of approximately $2.4 billion, as we believe this value to be the best indication of the value of the ownership distributed to the new equity owners. Our NRG plan of reorganization provided for the issuance of 100,000,000 shares of NRG common stock to the various creditors resulting in a calculated price per share of $24.04. Our reorganization value of approximately $9.1 billion was determined by adding our reorganized equity value of $2.4 billion, $3.7 billion of interest bearing debt and our other liabilities of $3.0 billion. The reorganization value represents the fair value of an entity before liabilities and approximates the amount a willing buyer would pay for the assets of the entity immediately after restructuring. This value is consistent with the voting creditors and bankruptcy court's approval of the NRG plan of reorganization.

We recorded approximately $3.9 billion of net reorganization income (comprised of a $4.2 billion gain from continuing operations and a $0.3 billion loss from discontinued operations) in the Predecessor Company's statement of operations for 2003, which includes the gain on the restructuring of equity and the discharge of obligations subject to compromise for less than recorded amounts, as well as adjustments to the historical carrying values of our assets and liabilities to fair market value.

Due to the adoption of Fresh Start as of December 5, 2003, the Reorganized NRG post-Fresh Start statement of operations and statement of cash flows have not been prepared on a consistent basis with the Predecessor Company's financial statements and are therefore not comparable in certain respects to the financial statements prior to the application of Fresh Start. The accompanying Consolidated Financial Statements have been prepared to distinguish between Reorganized NRG and the Predecessor Company.

	Company December 5, 2003	Debt Discharge and Exchange of Stock	Fresh Start Adjustments	Consolidation	NRG December 6, 2003
			(In millions)		
Current Assets	$ 1,718	$ 614	$ 4	$ 6	$ 2,342
Non-current Assets	8,172	(155)	(1,233)	41	6,825
Total Assets	$ 9,890	$ 459	$ (1,229)	$ 47	$ 9,167
Current Liabilities	2,190	999	1,187	1	4,377
Non-current Liabilities	9,458	(6,270)	(848)	46	2,386
Total Liabilities	11,648	(5,271)	339	47	6,763
Stockholders Equity	(1,758)	2,404	1,758	—	2,404
Total Liabilities and Stockholders Equity	$ 9,890	$ (2,867)	$ 2,097	$ 47	$ 9,167

APB No. 18, *"The Equity Method of Accounting for Investments in Common Stock,"* requires us to effectively push down the effects of Fresh Start reporting to our unconsolidated equity method investments and to recognize an adjustment to our share of the earnings or losses of an investee as if the investee were a consolidated subsidiary. As a result of pushing down the impact of Fresh Start to our West Coast Power affiliate, we determined that a contract based intangible asset with a one year remaining life, consisting of the value of West Coast Power's California Department of Water Resources energy sales contract, must be established and recognized as a basis adjustment to our share of the future earnings generated by West Coast Power. This adjustment reduced our equity earnings in the approximate amount of $116 million for the year ended December 31, 2004. This contract expired in December 2004.

Known trends that will affect our results in the future:

Acquisition of Texas Genco and Financing Transactions

On February 2, 2006, NRG acquired Texas Genco LLC by purchasing all of the outstanding equity interests in Texas Genco pursuant to the Acquisition Agreement, dated September 30, 2005, by and among NRG, Texas Genco, and the Sellers. Also see our detailed discussion in our Liquidity and Capital Resources section. Texas Genco is now a wholly-owned subsidiary of NRG, and will be managed and accounted for as a new business segment to be referred to as NRG Texas.

In order to facilitate the acquisition of Texas Genco, we entered into a series of financing transactions. Also see our detailed discussion in our Liquidity and Capital Resources section:

Debt instruments:

- $3.575 billion Term Loan Facility
- $1.0 billion Revolving Credit Facility
- $1.0 billion Letter of Credit Facility
- $1.2 billion in aggregate principal amount of 7.25% Senior Notes
- $2.4 billion in aggregate principal amount of 7.375% Senior Notes

Equity instruments:

- $485 million from the issuance of 2 million shares of 5.75% Preferred Stock, net of issuance costs
- $985 million from the issuance of 20,855,057 shares of our common stock, net of issuance costs

These transactions also facilitated the refinancing of our outstanding debt as well as the debt outstanding for Texas Genco upon acquisition.

Based on our current projections, our NRG Texas segment will be a profitable segment and will significantly increase our revenue and operating costs going forward. Partially offsetting this additional profit will be the increased interest expense due to the increased debt level as shown above. We have also increased the number of our outstanding shares by issuing approximately 35 million shares from both treasury and newly issued stock to the Sellers, as well as approximately 21 million newly issued shares to the public. This significant increase in outstanding shares will dilute our future earnings per share.

At this time, we anticipate that the net effect in 2006 will be positive to our future results of operations as well as to our earnings per share.

Acquisition of Remaining 50% Equity Interest in WCP

On December 27, 2005, we entered into purchase and sale agreements for projects co-owned with Dynegy. Under the agreements, we will acquire Dynegy's 50% ownership interest in WCP (Generation) Holdings, Inc., and become the sole owner of WCP's 1,808 MW of generation in Southern California. We anticipate that the transaction will close during the first quarter of 2006.

As of the date of acquisition we will consolidate the results of operations of WCP. When consolidated, the results of WCP will increase our revenues and cost of operations, but it will reduce our equity earnings. We anticipate that the net effect in 2006 will be positive to our results of operations.

Liquidity and Capital Resources

Significant Events during 2005

- The repurchase of $645 million in aggregate principal amount of our Second Priority Notes, resulting in $54 million of refinancing charges
- The issuance of $250 million of 3.625% Preferred Stock
- The execution of the Accelerated Share Repurchase Agreement whereby we repurchased $250 million of common stock
- Repatriation of $298 million of foreign funds utilizing the tax benefits of the American Jobs Creation Act of 2004
- Cash collateral payments of $405 million supporting our hedging activities
- Collection of $71 million in an arbitration award related to TermoRio
- Execution of the Texas Genco Acquisition Agreement and related financing commitments
- Sale of non-core assets resulting in $106 million in proceeds
- The announced signing of sales and purchase agreements for the sale of Audrain resulting in its reclassification as a discontinued operation

The following table summarizes the debt transactions during 2005 and subsequent transactions in 2006:

	Date of Transaction	Original Amount	Balance Outstanding at December 31, 2004	2005 activity and Outstanding at December 31, 2005	2006 activity and Outstanding at February 25, 2006
			(In millions)		
Xcel Promissory Note	Dec. 6, 2003	$ 10	$ 10	$ 10	$ 10
NRG 8% Second Priority Notes	Dec. 23, 2003-Jan. 28, 2004	1,725	1,725		
Repurchase of Notes	Jan-Mar, 2005			(41)	
Early redemption	Feb-Sep, 2005			(604)	
Ending balance Dec. 31, 2005				1,080	
Repurchase of Notes	Feb. 2, 2006				(1,080)
Ending balance Feb. 25, 2006					$ —
NRG Credit Facility Term loan	Dec. 23, 2003	950	450		
Repayments of Term Loans	Throughout 2005			(4)	
Ending balance Dec. 31, 2005				446	
Prepayment of Term Loan	Jan 2006				(446)
Ending balance Feb. 25, 2006					$ —
Letter of Credit facility	Dec. 23, 2003	250	350	350	
Terminating Letter of Credit facility	Feb. 2, 2006				(350)
Ending balance Feb. 25, 2006					$ —
Corporate Revolver*	Dec. 23, 2003	250	150	150	
Terminating Corporate Revolver*	Feb. 2, 2006				(150)
Ending balance Feb. 25, 2006*					$ —
New Sr. Secured Term loan	Feb. 2, 2006				3,575
New Funded LC Facility	Feb. 2, 2006				1,000
New Corporate Revolver*	Feb. 2, 2006				1,000
Ending balance Feb. 25, 2006					$ 5,575
7.25% Senior Notes due 2014	Feb. 2, 2006				1,200
7.375% Senior Notes due 2016	Feb. 2, 2006				2,400
Ending balance Feb. 25, 2006					$ 3,600
Total Corporate Level Debt*			$ 2,535	$ 1,886	$ 7,185

* Amount indicates capacity to borrow under NRG's revolver facilities only. Un-borrowed capacity is not included in total corporate level debt.

Sources of Funds

The principal sources of liquidity for our future operations and capital expenditures are expected to be existing cash on hand, cash flows from operations, and funds raised from new financing arrangements.

Cash Flows from Operations. Our operating cash flows are expected to be impacted by, among other things: (i) spark spreads generally; (ii) commodity prices (including demand for natural gas, coal, oil and electricity); (iii) the cost of ordinary course operations and maintenance expenses; (iv) planned and unplanned outages; (v) restrictions in the declaration or payments of dividends or similar distributions from our subsidiaries; and (vi) the timing and nature of asset sales. Following are additional sources of cash flows:

Letter of credit and revolver borrowing capacity. We had approximately $38 million of undrawn letter of credit capacity and $150 million of revolving credit capacity under our Amended Credit Facility as of December 31, 2005. On February 2, 2006 we terminated our Amended Credit Agreement and entered into a new Senior Credit Facility. The new Senior Credit Facility consists of a $3.575 billion term loan, $1.0 billion in a synthetic letter of credit facility and $1.0 billion in a revolver facility. Portions of the revolving credit facility are available as a swing-line facility and as a revolving letter of credit sub-facility. As of March 3, 2006, we had approximately $225 million of undrawn letter of credit capacity under our senior credit facility and $845 million of revolving credit capacity under our Senior Credit Facility. The balance of the revolver has been used to issue non-commercial letters of credit. See our discussion below on the Financing Transactions and Texas Genco Acquisition in this discussion and analysis.

Issuance of $250 million in 3.625% Preferred Stock. On August 11, 2005, we issued 250,000 shares of 3.625% Preferred Stock to Credit Suisse First Boston Capital LLC, or CSFB, in a private placement. As of December 31, 2005, 250,000 shares of the 3.625% Preferred Stock were issued and outstanding at a liquidation value, net of issuance costs of $246 million. Holders of the 3.625% Preferred Stock are entitled to receive, when, as and if declared by our Board of Directors, out of funds legally available therefore, cash dividends at the rate of 3.625% per annum, payable quarterly in arrears on March 15, June 15, September 15 and December 15 of each year, commencing on December 14, 2005. On or after August 11, 2015, we may redeem, subject to certain limitations, some or all of the 3.625% Preferred Stock with cash at a redemption price equal to 100% of the liquidation preference, plus accumulated but unpaid dividends, including liquidated damages, if any, to the redemption date. Proceeds from the sale of the 3.625% preferred securities along with cash on hand were used to redeem $229 million in Second Priority Notes, pay an early redemption penalty of $18 million and pay accrued interest of $4 million on the redeemed notes.

Settlements and Asset Sales. On February 15, 2005 we received a $71 million settlement payment from Petrobras, our former partner in our TermoRio project in Brazil. During 2005, we received approximately $106 million in proceeds from the sale of our interest in non-core projects, including our interest in Enfield, Northbrook New York and Northbrook Energy and remaining interest in Kendall.

Repatriation of Foreign Funds. During the third quarter of 2005 we repatriated approximately $298 million of accumulated foreign earnings. Only a portion of this amount represents the cumulative earnings and profits from the foreign entities. Those earnings resulted in approximately $5 million of tax expense. This repatriation was initiated to utilize the tax benefits of the American Jobs Creation Act of 2004 which expired on December 31, 2005.

Uses of Funds

Our requirements for liquidity and capital resources, other than for operating our facilities, can generally be categorized by the following: (i) Commercial Operations (formerly referred to as PMI) activities; (ii) capital expenditures; (iii) corporate financial restructuring and (iv) project finance requirements.

(i) Commercial Operations

Commercial Operations activities comprise the single largest requirement for liquidity and capital resources. These liquidity requirements are primarily driven by: (i) margin and collateral posted with counter-parties; (ii) initial collateral required to establish trading relationships; (iii) timing of disbursements and receipts (i.e., buying fuel before receiving energy revenues); and (iv) initial collateral for large structured transactions. As of December 31, 2005, Commercial Operations had total cash collateral outstanding of $438 million, and $227 million outstanding in letters of credit to third parties primarily to support our economic hedging activities.

Future liquidity requirements may change based on our hedging activity, fuel purchases, future market conditions, including forward prices for energy and fuel and market volatility. In addition, liquidity requirements are dependent on our credit ratings and general perception of creditworthiness.

Following the Acquisition, our debt instruments permit us to grant secured priority liens on our assets to support certain trading activities which will provide an alternative to posting cash deposits and letters of credit. See our discussion below on the Financing Transactions and Texas Genco Acquisition in this discussion and analysis.

(ii) Capital Expenditures

Capital expenditures were $106 million for the year ended December 31, 2005, and $119 million for the year ended December 31, 2004. Capital expenditures in 2005 related to the continued PRB conversions, associated conveyor track and emissions compliance upgrades at our Western New York plants. Indian River's PRB conversion is underway at units 1-3. Unit 4 at Indian River, originally targeted for conversion, was deemed incompatible for PRB coal during 2005. Capital expenditures in 2004 also related primarily to the conversion of our western New York plants to PRB coal, as well as the Playford 2 refurbishment at our Flinders operation in Australia and planned outages across our fleet.

(iii) Corporate Financial Restructuring

Repurchase and redemption of Second Priority Notes during 2005. In conjunction with our goal of improving our credit ratings we manage our capital allocation around a target of 45%-60% debt to capital ratio. As such, we may elect periodically to modify our corporate financial structure. Throughout 2005, we repurchased or redeemed, and subsequently retired, $645 million of our Second Priority Notes. Total costs associated with the repurchase and redemptions was $52 million in early redemption premium, $9 million in accrued but unpaid interest, and $7 million in accrued but unpaid liquidated damages.

Redemption of Second Priority Notes and Termination of Credit Facility during 2006. On January 31, 2006 we repaid $446 million in outstanding principal plus $3 million in accrued interest and terminated our term loan under our Amended Credit Facility. On February 2, 2006, we repurchased and retired $1.08 billion of our Second Priority Notes, pursuant to a tender offer, paying approximately $138 million in consent premiums and accrued interest. On February 2, 2006 we defeased the remaining un-tendered $0.4 million of our Second Priority Notes, effectively terminating our obligations with respect to such Notes. Also on February 2, 2006 we paid $1 million in accrued fees and terminated our revolving facility and our funded letter of credit facility under our Amended Credit Facility, and simultaneously issued new indebtedness, as described below in *New Financing Structure and Texas Genco Acquisition* in this discussion and analysis.

Accelerated Share Repurchase Plan. On August 11, 2005, we entered into an Accelerated Share Repurchase Agreement with CSFB, pursuant to which we repurchased $250 million of our common stock on that date that equaled a total of 6,346,788 shares, which were held in treasury. We funded the repurchase with cash on hand. On March 3, 2006, we paid to CSFB a cash purchase price adjustment of approximately $7 million based upon the weighted average value of NRG's common stock over a period of approximately six months, subject to a minimum price of 97% and a maximum price of 103% of the closing price per share on August 10, 2005, or $39.39.

Preferred Dividend Payments. During 2005, we paid approximately $17 million in four dividend payments to our holders of our 4% Preferred Stock. On December 15, 2005, we made an approximate $3 million dividend payment to our 3.625% preferred shareholders of record as of December 1, 2005.

(iv) Project Finance Requirements

We are a holding company and conduct our operations primarily through subsidiaries. Historically, we have utilized project-level debt to fund a significant portion of the capital expenditures and investments required to construct our power plants and related assets. Consistent with our strategy, we may seek, where available on commercially reasonable terms, project-level debt in connection with the assets or businesses of our affiliates, or we may develop, construct or acquire new projects. Project-level borrowings are substantially non-recourse to other subsidiaries, affiliates and us, and are generally secured by the capital stock, physical assets, contracts and cash flow of the related project subsidiary or affiliate being financed. Some of these project financings may require us to post collateral in the form of cash or an acceptable letter of credit.

Principal on short-term debt, long-term debt and capital leases as of December 31, 2005 are due and payable in the following periods (in millions):

Subsidiary/Description	Total	2006	2007	2008	2009	2010	Thereafter
Xcel Energy Note	$ 10	$ 10	$ —	$ —	$ —	$ —	$ —
Amended Credit Facility due Dec. 2011	796	796	—	—	—	—	—
8% Second Priority Notes	1,080	1,080	—	—	—	—	—
NRG Energy Center Minneapolis, due 2013 and 2017	111	8	9	10	11	11	62
NRG Peaker Finance Co LLC	297	7	11	13	15	20	231
Flinders Power Finance Pty	177	6	14	4	8	18	127
Camas Pwr BLR LP Bank facility	4	3	1	—	—	—	—
Camas Pwr BLR LP Bonds	3	1	2	—	—	—	—
Itiquira Energetica S.A., due January 2012	19	3	3	3	3	3	4
Itiquira Energetica S.A., due December 2013	30	4	4	4	4	4	10
Subtotal Debt, Bonds and Notes	2,527	1,918	44	34	41	56	434
Saale Energie GmbH, Schkopau (capital lease)	214	61	34	28	21	10	60
Conemaugh Fuels LLC (capital lease)	—	—	—	—	—	—	—
Subtotal Capital Leases	214	61	34	28	21	10	60
Total Debt	$2,741	$1,979	$ 78	$ 62	$ 62	$ 66	$ 494

These amounts reflect scheduled amortization of principal as of December 31, 2005, with the exception of the 8% Second Priority Notes, and our Credit Facility, for which 2006 amounts reflect early termination. The table below reflects the new short-term and long-term debt amounts and the expected future payments. Also see our discussion below on the Financing Transactions and Texas Genco Acquisition in this discussion and analysis, as well as Item 15 — Note 17 to the Consolidated Financial Statements for further discussion on events that may affect debt payment schedules.

Description	Total	2006	2007	2008	2009	2010	Thereafter
New Credit Facility due Feb 2013	$3,575	$ 26	$ 36	$ 36	$ 36	$ 36	$ 3,405
7.25% Notes due 2014	1,200	—	—	—	—	—	1,200
7.375% Notes due 2016	2,400	—	—	—	—	—	2,400
Total Debt	$7,175	$ 26	$ 36	$ 36	$ 36	$ 36	$ 7,005

Historical Cash Flows

We have obtained cash from operations, proceeds from repayment of outstanding notes receivable, proceeds from the sale of certain assets and the proceeds from the sale of preferred stock. We have used these funds to finance operations, reduce our outstanding Second Priority Notes, repurchase common stock through an accelerated share repurchase plan, service debt obligations, finance capital expenditures, and meet other cash and liquidity needs. The following table reflects the changes in cash flows for the comparative years and we include a detailed discussion on the changes during the last year. All cash flow categories include the cash flows from continuing operations and discontinued operations:

	Reorganized NRG			Predecessor Company
	Year Ended December 31, 2005	Year Ended December 31, 2004	For the Period December 6-December 31, 2003	For the Period January 1-December 5, 2003
	(In millions)			
Net cash provided (used) by operating activities	$ 68	$ 645	$ (589)	$ 238
Net cash (used) provided by investing activities	158	184	363	(186)
Net cash provided (used) by financing activities	(830)	(284)	393	(30)

Net Cash Provided (Used) By Operating Activities

For the year ended December 31, 2005, net cash provided by operating activities decreased by $580 million compared to the year ended December 31, 2004. This is primarily due to the following reasons:

- Net income decreased by $102 million for the year ended December 31, 2005 compared to the year ended December 31, 2004.
- Due to the sharp increase in the sale price per MWh, our derivative contract terms required collateral deposits of $405 million during 2005, compared to $7 million during 2004, a difference of $398 million. As of December 31, 2005 we had collateral deposits of $438 million and we expect $405 of this amount to be refunded during 2006 as the underlying contracts expire.
- A decrease of $60 million in distributions from our equity investments during 2005 compared to 2004. The majority of this decrease is from our WCP investment. Since the expiration of the CDWR contract on December 31, 2004, WCP's profit has been significantly reduced and has subsequently distributed $59 million less dividends during 2005 compared to 2004.
- Receipt of $100 million in 2004 related to the settlement with Xcel Energy.

Net Cash Provided (Used) By Investing Activities

For the year ended December 31, 2005, net cash provided by investing activities was $26 million less than for the year ended December 31, 2004. This decrease is due to the following mix of investment activities:

- During 2004, we sold interests in non-core assets for proceeds totaling $304 million. As most of the non-core assets were sold during 2004 and management began focusing on different areas of operation, during 2005 proceeds from the sale of non-core assets fell by $198 million.
- Our capital expenditures were $13 million less during 2005 compared to 2004 due to lower PRB conversion expenditures.
- During 2005, proceeds from payments on our notes receivable increased by $82 million, primarily due to the payment from TermoRio of approximately $71 million as the dispute related to this note was settled.

- In comparison to an increase of $27 million during 2004, restricted cash balances decreased by $46 million, a difference of $72 million. This amount is explained by the release of approximately $38 million of restricted cash at our Flinders facility as a result of our refinancing of Flinders' debt, as well as the release of accounts from restrictions during post bankruptcy operations.

Net Cash Provided (Used) By Financing Activities

For the year ended December 31, 2005, net cash used by financing activities increased by $546 million in comparison to 2004. The activity for 2005 consisted of:

- The redemption and repurchase of $645 million of our Second Priority Secured Notes. In order to redeem our Second Priority Notes, we issued $420 million of the 4% Preferred Stock in December 2004, and subsequently, $250 million of the 3.625% Preferred Stock in August of 2005. The timing difference between the receipt of cash from our 4% Preferred Stock in December 2004 and the redemption of debt in 2005 is the primary reason for the increase in cash used for financing activities in 2005 in comparison to 2004.
- Our accelerated share repurchase payment of $250 million.
- Payment of $46 million for financing costs to refinance our Flinders' debt.
- Payment of $20 million of dividends to holders of our preferred stock.

During 2004, the primary use of funds for financing activities was related to the repayment of project level debt at McClain of approximately $157 million and regular debt payments of approximately $135 million.

Other Liquidity Matters — NOLs and Deferred Tax Assets

As of December 31, 2005, we U.S. NOL carryforwards of approximately $93 million. We believe that it is more likely than not that the benefit will not be realized on a substantial portion of the deferred tax assets relating to future tax benefits. This assessment includes consideration of positive and negative factors, including our current financial position, historical results of operations and current results of operations, projected future taxable income, including projected operating and capital gains, and available tax planning strategies. Therefore, as of December 31, 2005, a consolidated valuation allowance of $756 million was recorded against the net deferred tax assets, in accordance with SFAS No. 109. However, we have not provided a valuation allowance for approximately $15 million of net deferred tax assets which consist of mark-to-market adjustments per SFAS 133 and utilization of carryover net operating losses to the extent of taxable income generated for the year ended December 31, 2005.

Conclusion on Future Liquidity

As of December 31, 2005 our liquidity was $758 million and included $570 million of unrestricted and restricted cash. Our liquidity also included $150 million of available capacity under our revolving line of credit and $38 million of availability under our letter of credit facility. As of December 31, 2004 our liquidity was $1.6 billion and included $1.2 billion of unrestricted and restricted cash. Our liquidity also included $150 million of available capacity under our revolving line of credit and $193 million of availability under our letter of credit facility.

Based on the new financing transactions, but assuming the cash balances as of December 31, 2005 and the outstanding instruments as of March 3, 2006, our liquidity would be $1.6 billion and includes $570 million of unrestricted and restricted cash. Our liquidity include $845 million of available capacity under our new Revolving Credit Facility and $225 million of availability under our new synthetic Letter of Credit Facility, as of March 3, 2006. Please see discussion below for further detail.

Management believes that these amounts and cash flows from operations will be adequate to finance capital expenditures, to fund dividends to our preferred shareholders and other liquidity commitments for the next 12 months. Management continues to regularly monitor the company's ability to finance the needs of its operating, financing and investing activity in a manner consistent with its intention to maintain a debt to capital ratio within a range of 45%-60%.

Known Trends and Other Factors Affecting our Liquidity

New Financing Structure and Texas Genco Acquisition

On February 2, 2006, NRG acquired Texas Genco LLC, a Delaware limited liability company, by purchasing all of the outstanding equity interests in Texas Genco pursuant to the Acquisition Agreement, dated September 30, 2005, by and among NRG, Texas Genco, and each of the direct and indirect owners of Texas Genco. The purchase price of approximately $6.1 billion consisted of $4.4 billion in cash and the issuance of approximately 35.4 million shares of NRG's common stock valued at $1.7 billion. This amount is subject to adjustment due to acquisition costs. The value of our common stock issued to the Sellers was based on our average stock price immediately before and after the closing date of February 2, 2006. The Acquisition includes the assumption of approximately $2.7 billion of Texas Genco debt. Texas Genco is now a wholly-owned subsidiary of NRG, and will be managed and accounted for as a new business segment to be referred to as NRG Texas.

The Texas Genco acquisition was partially funded at closing with the combination of (i) cash proceeds received upon the issuance and sale in a public offering of 20,855,057 shares of NRG's common stock at a price of $48.75 per share; (ii) cash proceeds received upon the issuance and sale of $3.6 billion of unsecured high yield notes; (iii) cash proceeds received upon the issuance and sale in a public offering of 2,000,000 shares of mandatory convertible preferred stock at a price of $250 per share; (iv) funds borrowed under a new senior secured credit facility consisting of a $3.575 billion term loan facility, a $1.0 billion revolving credit facility and a $1.0 billion synthetic letter of credit facility; and (v) cash on hand.

Texas Genco owns approximately 11,000 MW of net operating generation capacity, and sells power and related services in the Texas' ERCOT market.

New Senior Credit Facility

On February 2, 2006, we also entered into a new senior secured first priority credit facility with a syndicate of financial institutions, including Morgan Stanley Senior Funding, Inc., as administrative agent, Morgan Stanley & Co. Inc., as collateral agent, and Morgan Stanley Senior Funding, Inc. and Citigroup Global Markets Inc. as joint lead book-runners, joint lead arrangers and co-documentation agents providing for up to an aggregate amount of $5.575 billion, or the New Senior Credit Facility. The New Senior Credit Facility consists of a $3.575 billion term loan facility, or the Term Loan Facility, a $1.0 billion revolving credit facility, or the Revolving Credit Facility, and a $1.0 billion synthetic letter of credit facility, or the Letter of Credit Facility. The New Senior Credit Facility replaced our then existing senior secured credit facility. The Term Loan Facility will mature on February 2, 2013 and will amortize in 27 consecutive equal quarterly installments of 0.25% of the original principal amount of the Term Loan Facility with the balance payable on the seventh anniversary thereof. The full amount of the Revolving Credit Facility will mature on February 2, 2011. The Letter of Credit Facility will mature on February 2, 2013 and no amortization will be required in respect thereof.

The New Senior Credit Facility is guaranteed by substantially all of our existing and future direct and indirect subsidiaries, with certain customary or agreed-upon exceptions for unrestricted foreign subsidiaries, project subsidiaries and certain other subsidiaries. In addition, the New Senior Credit Facility is secured by liens on substantially all of our assets and the assets of our subsidiaries, with certain customary or agreed-upon exceptions for unrestricted foreign subsidiaries, project subsidiaries and certain other subsidiaries. The capital stock of substantially all of our subsidiaries, with certain exceptions for unrestricted subsidiaries, foreign subsidiaries and project subsidiaries, has been pledged for the benefit of the New Senior Credit Facility lenders.

The New Senior Credit Facility is also secured by a first-priority perfected security interest in all of the property and assets owned at-any time or acquired by us and our subsidiaries, other than certain limited exceptions. These exceptions include assets such as the assets of certain unrestricted subsidiaries, equity interests in certain of our project affiliates that have non-recourse debt financing, and voting equity interests in excess of 66% of the total outstanding voting equity interest of certain of our foreign subsidiaries.

The New Senior Credit Facility contains customary covenants, which, among other things require us to meet certain financial tests, including a minimum interest coverage ratio and a maximum leverage ratio, each at the corporate level and on a consolidated basis, and further limits our ability to, among other things:

- incur indebtedness and liens and enter into sale and lease-back transactions;
- make investments, loans and advances;
- engage in mergers, acquisitions, consolidations and asset sales;
- pay dividends and make other restricted payments;
- enter into transactions with affiliates;
- make capital expenditures;
- make debt payments; and
- make certain changes to the terms of material indebtedness.

Senior Notes

On February 2, 2006, we completed the sale of (i) $1.2 billion in aggregate principal amount of 7.25% senior notes due 2014, or 7.25% Senior Notes, and (ii) $2.4 billion in aggregate principal amount of 7.375% senior notes due 2016, or 7.375% Senior Notes, collectively the Senior Notes. The Senior Notes were issued under an Indenture, dated February 2, 2006, between us and Law Debenture Trust Company of New York, as Trustee, as supplemented by a First Supplemental Indenture, dated February 2, 2006, between us, the guarantors named therein and the Trustee, relating to the 7.25% Senior Notes, and as supplemented by a Second Supplemental Indenture, dated February 2, 2006,(together with the Indenture and the First Supplemental Indenture, the Indentures) between us, the guarantors named therein and the Trustee, relating to the 7.375% Senior Notes. The Indentures provide, among other things, that the Senior Notes will be senior unsecured obligations of NRG.

Interest is payable on the Senior Notes on February 1 and August 1 of each year beginning on August 1, 2006 until their maturity dates — February 1, 2014 for the 7.25% Senior Notes and February 1, 2016 for the 7.375% Senior Notes.

Prior to February 1, 2010 for the 7.25% Senior Notes and prior to February 1, 2011 for the 7.375% Senior Notes, we may redeem all or a portion of the series of Senior Notes at a price equal to 100% of the principal amount plus a "make whole" premium and accrued interest. On or after February 1, 2010 for the 7.25% Senior Notes and on or after February 1, 2011 for the 7.375% Senior Notes, we may redeem all or a portion of the series of Senior Notes at redemption prices set forth in the Indentures. In addition, at any time prior to February 1, 2009, we may redeem up to 35% of the aggregate principal amount of the series of Senior Notes with the net proceeds of certain equity offerings at the redemption price set forth in the Indentures.

The terms of the Indentures, among other things, limit our ability and certain of our subsidiaries' ability to:

- make restricted payments;
- restrict dividends or other payments of subsidiaries;
- incur additional debt;
- engage in transactions with affiliates;
- create liens on assets;

- engage in sale and leaseback transactions; and
- consolidate, merge or transfer all or substantially all of its assets and the assets of its subsidiaries.

The Indentures provide for customary events of default which include, among others, nonpayment of principal or interest; breach of other agreements in the Indentures; defaults in failure to pay certain other indebtedness; the rendering of judgments to pay certain amounts of money against us and our subsidiaries; the failure of certain guarantees to be enforceable; and certain events of bankruptcy or insolvency. Generally, if an event of default occurs, the Trustee or the holders of at least 25% in principal amount of the then outstanding series of Senior Notes may declare all of the Senior Notes of such series to be due and payable immediately.

Second Lien Structure

Before the Acquisition, Texas Genco's capital structure permitted the grant of second priority liens on its assets as security for their obligations under certain long-term power sales agreements and related hedges. The Credit Agreement for New Senior Credit Facility and the Indentures, which became effective as of February 2, 2006, allow these arrangements to remain in place. In addition, the new debt instruments also permit us to grant second priority liens on our other assets in the United States in order to secure obligations under power sales agreements and related hedges, within certain limits. The seven trading counterparties of Texas Genco who held second priority liens on Texas Genco's assets as of February 2, 2006, have been offered a second priority lien on NRG's other assets under the new structure, as additional collateral. Going forward, NRG anticipates that it will use the second lien structure to reduce the amount of cash collateral and letters of credit that it may otherwise be required to post from time to time to support its obligations under long term power sales and related hedges. Also see Item 1 — "Business" section — within the "Power Marketing and Commercial Operations" discussion for quantified utilization as of December 31, 2005.

Mandatory Convertible Preferred Stock

On February 2, 2006, we completed the issuance of 2 million shares of 5.75% mandatory convertible preferred stock, or the 5.75% Preferred Stock, at an offering price of $250 per share for total net proceeds after deducting offering expenses and underwriting discounts of approximately $485 million. Dividends on the 5.75% Preferred Stock are $14.375 per share per year, and are due and payable on a quarterly basis beginning on March 15, 2006. The 5.75% Preferred Stock will automatically convert into common stock on March 16, 2009, or the Conversion Date, at a rate that is dependent upon the applicable market value of our common stock. If the applicable market value of our common stock is $60.45 a share or higher at the Conversion Date, then the 5.75% Preferred Stock is convertible at a rate of 4.1356 shares of our common stock for every share of 5.75% Preferred Stock outstanding. If the applicable market value of our common stock is less than or equal to $48.75 per share at the Conversion Date, then the 5.75% Preferred Stock is convertible at a rate of 5.1282 shares of our common stock for every share of 5.75% Preferred Stock outstanding. If the applicable market value of our common stock is between $48.75 per share and $60.45 per share at the Conversion Date, then the 5.75% Preferred Stock is convertible into common stock at a rate that is between 4.1356 per share and 5.1282 per share of common stock.

Common Stock

On January 31, 2006, we completed the issuance of 20,855,057 shares of our common stock at an offering price of $48.75 per share for total net proceeds after deducting offering expenses and underwriting discounts of approximately $985 million.

Sale of Audrain

Audrain has an approximate total of $355 million in long and short-term debt. We anticipate that the sale of Audrain will close during the first half of 2006 upon which these balances will be eliminated.

Brownfield Developments

As part of our strategy to reinvest capital in our existing assets for reason of repowering and expansion of current generation sites, management is evaluating opportunities within our core areas of operations.

During the third quarter, we received a Title V Air Permit from the Louisiana Department of Environmental Quality to add a fourth unit of generating capacity at our Big Cajun II Generating Station in New Roads, Louisiana. The total capital expenditure expected from the construction of the 675 MW expansion project is approximately $1 billion and would take four years to build. Our Big Cajun II facility serves the electricity needs of Louisiana's 11 electric cooperatives and we believe that there is additional unmet demand for coal-fired generation in the area. We are currently evaluating potential partners and customers for this project as they are critical to the consideration of when to proceed with this project.

Operations in Australia

NRG is currently considering strategic alternatives with respect to Australia either to reposition its assets more effectively within the National Electricity Market or to monetize its investment. We will seek to determine the best option to optimize our investment during 2006.

Off-Balance Sheet Items

Obligations Under Certain Guarantee Contracts

NRG and certain of its subsidiaries enter into guarantee arrangements in the normal course of business to facilitate commercial transactions with third parties. These arrangements include financial and performance guarantees, stand-by letters of credit, debt guarantees, surety bonds and indemnifications. See Note 29, Guarantees and Other Contingent Liabilities for further details of the guarantee arrangements.

Retained or Contingent Interests

NRG does not have any material retained or contingent interests in assets transferred to an unconsolidated entity.

Derivative Instrument obligations

On August 11, 2005 NRG issued the 3.625% Preferred Stock which includes a conversion feature which is considered a derivative per FAS 133. Although it is considered a derivative, it is exempt from derivative accounting as it is excluded from the scope pursuant to paragraph 11(a) of SFA 133. Despite this exclusion, per the guidance of EITF Topic D-98 the conversion feature must be marked-to-market. Currently, the conversion feature is valued at $0 as our stock price is outside the conversion range. See Note 18 Capital Structure for further discussion.

Obligations Arising Out of a Variable Interest in an Unconsolidated Entity

Variable Interest in Equity investments

As of December 31, 2005, we have not entered into any financing structure that is designed to be off-balance sheet that would create liquidity, financing or incremental market risk or credit risk to us. However, we have numerous investments with an ownership interest percentage of 50% or less in energy and energy related entities that are accounted for under the equity method of accounting. Our pro-rata share of non-recourse debt held by unconsolidated affiliates was approximately $178 million and $252 million as of December 31, 2005 and December 31, 2004, respectively. This indebtedness may restrict the ability of these subsidiaries to issue dividends or distributions to us. In the normal course of business we may be asked to loan funds to unconsolidated affiliates on both a long and short-term basis. Such transactions are generally accounted for as accounts payable and receivable to/from affiliates and notes payable/receivable to/from affiliates and if appropriate, bear market-based interest rates.

New Synthetic Letter of Credit Facility and Revolver Facility

Under the New Senior Credit Facility we entered into on February 2, 2006, we have a $1.0 billion synthetic Letter of Credit Facility that is unfunded directly by NRG, and a $1.0 billion senior Revolving Credit Facility. The synthetic Letter of Credit Facility is secured by a $1.0 billion cash collateral deposit, held by Deutsche Bank AG, New York Branch as the Issuing Bank. Under the synthetic Letter of Credit Facility, we are allowed to issue letters of credit to support our obligations under commodity hedging or power purchase arrangements. We are permitted to issue up to $300 million in unfunded letters of credit under our Revolving Credit Facility for ongoing working capital requirements and for general corporate purposes, including acquisitions that are permitted under the New Senior Credit Facility, or revolver letters of credit.

As of March 3, 2006, we had issued $775 million in funded letters of credit under the Letter of Credit Facility. Of this amount, a portion was issued to support obligations under terminated NRG and Texas Genco letter of credit facilities. As of March 3, 2006, we had issued $155 million in revolver letters of credit, a portion of which supports non-commercial letter of credit obligations under the terminated NRG and Texas Genco letters of credit facilities.

Contractual Obligations and Commercial Commitments

We have a variety of contractual obligations and other commercial commitments that represent prospective cash requirements in addition to our capital expenditure programs. The following is a summarized table of contractual obligations. See additional discussion in Item 15 — Notes 17 and 25 to the Consolidated Financial Statements.

	Payments Due by Period as of December 31, 2005				
Contractual Cash Obligations	**Total**	**Short-term**	**2-3 Years**	**4-5 Years**	**After 5 Years**
			(In millions)		
Long-term debt (including estimated interest)	$3,600	$ 201	$ 391	$ 408	$ 2,600
Capital lease obligations (including estimated interest)	406	77	90	52	187
Operating leases	150	25	37	27	61
Coal purchase and transportation obligations	416	192	154	52	18
Total contractual cash obligations	$4,572	$ 495	$ 672	$ 539	$ 2,866

	Amount of Guarantee Liabilities Expiration per Period as of December 31, 2005				
Guarantee Type	**Total Amounts Committed**	**Short-term**	**2-3 Years**	**4-5 Years**	**After 5 Years**
			(In millions)		
Funded standby letters of credit	$ 312	$ 312	$ —	$ —	$ —
Unfunded standby letters of credit	9	9	—	—	—
Surety bonds	4	4	—	—	—
Asset sales guarantee obligations	123	—	13	—	110
Commodity sales guarantee obligations	91	62	12	14	3
Other guarantees	91	—	1	—	90
Total guarantees	$ 630	$ 387	$ 26	$ 14	$ 203

We have a variety of contractual obligations and other commercial commitments that represent prospective cash requirements in addition to our capital expenditure programs, as discussed in Item 15 —

Note 25, *Commitments and Contingencies*, to the Consolidated Financial Statements for a discussion of commitments and contingencies that also include contractual obligations and commercial commitments that occurred during 2005.

Derivative Instruments

We may enter into long-term power sales contracts, long-term gas purchase contracts and other energy related commodities financial instruments to mitigate variability in earnings due to fluctuations in spot market prices, to hedge fuel requirements at generation facilities and protect fuel inventories. In addition, in order to mitigate interest rate risk associated with the issuance of our variable rate and fixed rate debt, we enter into interest rate swap agreements.

The tables below disclose the trading activities that include non-exchange traded contracts accounted for at fair value. Specifically, these tables disaggregate realized and unrealized changes in fair value; identify changes in fair value attributable to changes in valuation techniques; disaggregate estimated fair values at December 31, 2005 based on whether fair values are determined by quoted market prices or more subjective means; and indicate the maturities of contracts at December 31, 2005.

Derivative Activity Gains/(Losses)

	(In millions)
Fair value of contracts at December 31, 2004	$ (43)
Contracts realized or otherwise settled during the period	129
Changes in fair value	(490)
Fair value of contracts at December 31, 2005	$(404)

Sources of Fair Value Gains/(Losses)

	Fair Value of Contracts as of December 31, 2005				
	Maturity Less Than 1 Year	Maturity 1-3 Years	Maturity 4-5 Years	Maturity in Excess of 5 Years	Total Fair Value
			(In millions)		
Prices actively quoted	$ (243)	$ (12)	$ —	$ —	$ (255)
Prices based on models and other valuation methods	2	(22)	(10)	(38)	(68)
Prices provided by other external sources	(53)	(1)	6	(33)	(81)
Total	$ (294)	$ (35)	$ (4)	$ (71)	$ (404)

We may use a variety of financial instruments to manage our exposure to fluctuations in foreign currency exchange rates on our international project cash flows, interest rates on our cost of borrowing and energy and energy related commodities prices.

Critical Accounting Policies and Estimates

Our discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of these financial statements and related disclosures in compliance with generally accepted accounting principles, or GAAP, requires the application of appropriate technical accounting rules and guidance as well as the use of estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosures of contingent assets and liabilities. The application of these policies necessarily involves judgments regarding future events, including the likelihood of success of particular projects, legal and regulatory challenges. These judgments, in and of themselves, could materially impact the financial statements and disclosures based on varying assumptions, which may be appropriate to use. In addition, the financial and operating environment also may have a significant effect, not only on the operation of the business, but on the results reported through the application of accounting measures used in preparing the financial statements and related disclosures, even if the nature of the accounting policies have not changed.

On an ongoing basis, we evaluate our estimates, utilizing historic experience, consultation with experts and other methods we consider reasonable. In any case, actual results may differ significantly from our estimates. Any effects on our business, financial position or results of operations resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known.

Our significant accounting policies are summarized in Item 15 — Note 2 to the Consolidated Financial Statements. We identify our most critical accounting policies as those that are the most pervasive and important to the portrayal of our financial position and results of operations, and that require the most difficult, subjective and/or complex judgments by management regarding estimates about matters that are inherently uncertain.

Accounting Policy	Judgments/Uncertainties Affecting Application
Revenue Recognition and Derivative Activity	• Assumptions used in valuation models • Market maturity and economic conditions • Contract interpretation • Market conditions in the energy industry, especially the effects of price volatility on contractual commitments • Documentation requirements • Market conditions in foreign countries • Regulatory and political environments and requirements
Income Taxes and Valuation Allowance for Deferred Tax Assets	• Ability of tax authority decisions to withstand legal challenges or appeals • Anticipated future decisions of tax authorities • Application of tax statutes and regulations to transactions. • Ability to utilize tax benefits through carrybacks to prior periods and carryforwards to future periods.
Impairment of Long Lived Assets	• Recoverability of investment through future operations • Regulatory and political environments and requirements • Estimated useful lives of assets • Environmental obligations and operational limitations • Estimates of future cash flows • Estimates of fair value (fresh start) • Judgment about triggering events
Goodwill and Other Intangible Assets	• Estimated useful lives for finite-lived intangible assets • Judgment about impairment triggering events • Estimates of reporting unit's fair value • Fair value estimate of certain power sales and fuel contracts using forward pricing curves as of the closing date over the life of each contract
Contingencies	• Estimated financial impact of event(s) • Judgment about likelihood of event(s) occurring

Revenue Recognition and Derivative Instruments

We record revenues using two methods of accounting: accrual accounting and mark-to-market accounting. We describe our use of accrual accounting, including the application of hedge accounting, in more detail in Note 2 to the Consolidated Financial Statements. In January 2001, we adopted SFAS 133, as amended by SFAS 137, SFAS 138 and SFAS 149. SFAS 133, as amended, requires us to mark-to-market all derivatives on the balance sheet. In some cases hedge accounting may apply. The criteria used to determine if hedge accounting treatment is appropriate are a) the designation of the hedge to an underlying exposure, b) whether or not the overall risk is being reduced and c) if there is correlation between the value of the derivative instrument and the underlying obligation. Formal documentation of the hedging relationship, the nature of the underlying risk, the risk management objective, and the means by which effectiveness will be assessed is created at the inception of the hedge. Changes in the fair value of non-hedge derivatives are immediately recognized in earnings. Changes in the fair value of derivatives accounted for as hedges are either recognized in earnings as an offset to the changes in the fair value of the related hedged assets, liabilities and firm commitments or for forecasted transactions, deferred and recorded as a component of accumulated other comprehensive income, or OCI, until the hedged transactions occur and are recognized in earnings.

Derivative instruments valuation assets and liabilities consist of a combination of energy and energy-related derivative contracts. While some of these contracts represent commodities or instruments for which prices are available from external sources, other commodities and certain contracts are not actively traded and are valued using modeling techniques to determine expected future market prices, contract quantities, or both. In determining the fair value of these derivative/financial instruments we use estimates, various assumptions, judgment of management and when considered appropriate third party experts in determining the fair value of these derivatives. However, future market prices and actual quantities will vary from those used in recording derivative instruments valuation assets and liabilities, and it is possible that such variations could be material.

Income Taxes and Valuation Allowance for Deferred Tax Assets

At December 31, 2005, we had a valuation allowance of approximately $756 million primarily related to our U.S. net deferred tax assets. In assessing the recoverability of our deferred tax assets, we consider whether it is more likely than not that some portion or all of the deferred tax assets will be realized. The ultimate realization of deferred tax assets is dependent upon the demonstration of a history of earnings and generation of future income during the periods in which those temporary differences will be deductible.

As of December 31, 2005, we have approximately $93 million of U.S. federal and state net operating loss (NOLs) carryforwards for financial reporting purposes. The ultimate utilization of our NOLs will depend on several factors, such as our ability to utilize tax benefits through carrybacks to prior periods and carryforwards to future periods, the application of tax statutes and regulations to transactions, the ability of tax authority decisions to withstand legal challenges or appeals, and anticipated future decisions of tax authorities.

We continue to be under audit for multiple years by taxing authorities in other jurisdictions. Considerable judgment is required to determine the tax treatment of a particular item that involves interpretations of complex tax laws. A tax liability has been recorded for certain tax filing positions where our inability to sustain the tax return position is probable and estimable. Such liabilities are based on management's judgment which considers the best estimate of the amount and probable outcome of the tax position, and it can take several years between the time when a liability is recorded and when the related filing position is resolved with the taxing authority. Management periodically reviews these matters and adjusts the liabilities recorded on the financial statements as appropriate.

Evaluation of Assets for Impairment and Other Than Temporary Decline in Value

In accordance with SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, we evaluate property, plant and equipment and intangible assets for impairment whenever indicators of impairment exist. Examples of such indicators or events are:

- Significant decrease in the market price of a long-lived asset;

- Available supply resources
- Transportation availability and reliability within and between regions
- Changes in the nature and extent of federal and state regulations

As part of our overall portfolio, we manage the commodity price risk of our generation assets by entering into various derivative or non-derivative instruments to hedge the variability in future cash flows from forecasted sales of electricity and purchases of fuel. These instruments include forward purchase and sale contracts, futures and option contracts traded on the New York Mercantile Exchange, and swaps and options traded in the over-the-counter financial markets. The portion of forecasted transactions hedged may vary based upon management's assessment of market, weather, operational, and other factors.

While some of the contracts we use to manage risk represent commodities or instruments for which prices are available from external sources, other commodities and certain contracts are not actively traded and are valued using other pricing sources and modeling techniques to determine expected future market prices, contract quantities, or both. We use our best estimates to determine the fair value of commodity and derivative contracts we hold and sell. These estimates consider various factors including closing exchange and over-the-counter price quotations, time value, volatility factors, and credit exposure. However, it is likely that future market prices could vary from those used in recording mark-to-market derivative instrument valuations, and such variations could be material.

We measure the sensitivity of our portfolio to potential changes in market prices using value at risk. Value at risk is a statistical model that attempts to predict risk of loss based on market price volatility. We calculate value at risk using a variance/covariance technique that models positions using a linear approximation of their value. Our value at risk calculation includes mark-to-market and non mark-to-market energy assets and liabilities.

We utilize a diversified value at risk model to calculate the estimate of potential loss in the fair value of our energy assets and liabilities including generation assets, load obligations and bilateral physical and financial transactions. The key assumptions for our diversified model include (1) a lognormal distribution of price returns, (2) one-day holding period, (3) a 95% confidence interval, (4) a rolling 24-month forward looking period and (5) market implied price volatilities and historical price correlations.

This model encompasses the following generating regions: ENTERGY, NEPOOL, NYPP, PJM, WSCC and MAIN. The estimated maximum potential loss in fair value of our commodity portfolio, including generation assets, load obligations and bilateral physical and financial transaction, calculated using the diversified VAR model is as follows:

	(In millions)
Year end December 31, 2005	$36.9
Average	27.6
High	45.9
Low	16.0
Year end December 31, 2004	26.7
Average	40.3
High	53.4
Low	26.7

In order to provide additional information for comparative purposes to our peers we also utilize value at risk to model the estimate of potential loss of financial derivative instruments included in derivative instruments valuation assets and liabilities. This estimation includes those energy contracts accounted for as a hedge under SFAS 133, as amended. The estimated maximum potential loss in fair value of the financial derivative instruments calculated using the diversified VAR model as of December 31, 2005 is approximately $37 million.

Due to the inherent limitations of statistical measures such as value at risk, the relative immaturity of the competitive markets for electricity and related derivatives, and the seasonality of changes in market prices, the value at risk calculation may not capture the full extent of commodity price exposure. Additionally, actual changes in the value of options may differ from the value at risk calculated using a linear approximation inherent in our calculation method. As a result, actual changes in the fair value of mark-to market energy assets and liabilities could differ from the calculated value at risk, and such changes could have a material impact on our financial results.

Interest Rate Risk

We are exposed to fluctuations in interest rates through our issuance of fixed rate and variable rate debt. Exposures to interest rate fluctuations may be mitigated by entering into derivative instruments known as interest rate swaps, caps, collars and put or call options. These contracts reduce exposure to interest rate volatility and result in primarily fixed rate debt obligations when taking into account the combination of the variable rate debt and the interest rate derivative instrument. Our risk management policy allows us to reduce interest rate exposure from variable rate debt obligations.

In January 2006, we entered into a series of new interest rate swaps. These interest rate swaps became effective on February 15, 2006 and are intended to hedge the risk associated with floating interest rates. For each of the interest rate swaps, we pay our counterparty the equivalent of a fixed interest payment on a predetermined notional value, and we receive quarterly the equivalent of a floating interest payment based on 3-month LIBOR calculated on the same notional value. All payments by us and our counterparties are made quarterly, and the LIBOR is determined in advance of each interest period. While the notional value of each of the swaps does not vary over time, the swaps are designed to mature sequentially. The total notional amount of these swaps as of February 25, 2006 was $2.15 billion. The notional amounts and maturities of each tranche of these swaps are as follows:

Period of Swap	Notional value	Maturity
1-year	$120 million	March 31, 2007
2-year	$140 million	March 31, 2008
3-year	$150 million	March 31, 2009
4-year	$190 million	March 31, 2010
5-year	$1.55 billion	March 31, 2011

As of December 31, 2005, we and our consolidating subsidiaries had various interest rate swap agreements with notional amounts totaling approximately $1.2 billion. If the swaps had been discontinued on December 31, 2005, we would have owed the counter-parties approximately $33.1 million. Based on the investment grade rating of the counterparties, we believe that our exposure to credit risk due to nonperformance by the counterparties to our hedging contracts is insignificant.

We have both long and short-term debt instruments that subject us to the risk of loss associated with movements in market interest rates. As of December 31, 2005, a 100 basis point change in interest rates would result in a $8.3 million change in interest expense on a rolling 12 month basis. When our new senior unsecured notes and new credit agreement are included, a 100 basis point change in interest rates would result in a $34 million change in interest expense on a rolling 12 month basis.

At December 31, 2005, the fair value of our fixed-rate long-term debt was $2.8 billion, compared with the carrying amount of $2.7 billion. We estimate that a 1% decrease in market interest rates would have increased the fair value of our fixed-rate long-term debt by approximately $33 million. When our new senior unsecured notes and new credit agreement are included, we estimate that a 1% decrease in market rates would increase the fair value of our fixed rate long term debt by approximately $456 million.

Liquidity Risk

Our collateral posted in support of our management of our electric generation facilities fluctuates based on amount of the portfolio hedged using collateralized contracts and market price movements. Based on a sensitivity analysis a $1 per MWh increase or decrease in electricity prices would cause a change in margin collateral outstanding of approximately $13 million. This sensitivity uses simplified assumptions and may not reflect actual market movements.

Credit Risk

Credit risk relates to the risk of loss resulting from non-performance or non-payment by counterparties pursuant to the terms of their contractual obligations. We monitor and manage the credit risk of NRG and its subsidiaries through credit policies which include an (i) established credit approval process, (ii) daily monitoring of counter-party credit limits, (iii) the use of credit mitigation measures such as margin, collateral, credit derivatives or prepayment arrangements, (iv) the use of payment netting agreements and (v) the use of master netting agreements that allow for the netting of positive and negative exposures of various contracts associated with a single counterparty. Risks surrounding counterparty performance and credit could ultimately impact the amount and timing of expected cash flows. We have credit protection within various agreements to call on additional collateral support if necessary. As of December 31, 2005, we held collateral support of approximately $205 million from counterparties.

A portion of our credit risk is related to transactions that are recorded in our Consolidated Balance Sheets. These transactions primarily consist of open positions from our marketing and risk management operation that are accounted for using mark-to-market accounting, as well as amounts owed by counterparties for transactions that settled but have not yet been paid. The following table highlights the credit quality and exposures related to these activities as of December 31, 2005:

	Exposure Before Collateral	Collateral	Net Exposure
		(In millions)	
Investment grade	$ 518	$ 96	$ 422
Non-investment grade	24	5	19
Not rated	164	25	139
Total	$ 706	$ 126	$ 580
Investment grade	73%	76%	73%
Non-investment grade	3%	4%	3%
Not rated	24%	20%	24%

Additionally, we have concentrations of suppliers and customers among electric utilities, energy marketing and trading companies and regional transmission operators. These concentrations of counterparties may impact NRG's overall exposure to credit risk, either positively or negatively, in that counterparties may be similarly affected by changes in economic, regulatory and other conditions.

NRG's exposure to significant counterparties greater than 10% of the net exposure of approximately $580 million was approximately $386 million as of December 31, 2005. We do not anticipate any material adverse effect on its financial position or results of operations as a result of nonperformance by any of its counterparties.

Currency Exchange Risk

We expect to continue to be subject to currency risks associated with foreign denominated distributions from our international investments. In the normal course of business, we may receive distributions denominated in the Euro, Australian Dollar and the Brazilian Real. We have historically engaged in a strategy of hedging foreign denominated cash flows through a program of matching currency inflows and outflows, and to the extent required, fixing the U.S. Dollar equivalent of net foreign denominated distributions with currency forward and swap agreements with highly credit worthy financial institutions. We would expect to enter into similar transactions in the future if management believes it to be appropriate.

As of December 31, 2005, neither we, nor any of our consolidating subsidiaries, had any material outstanding foreign currency exchange contracts.

Item 8 — *Financial Statements and Supplementary Data*

The financial statements and schedules are listed in Part IV, Item 15 of this Form 10-K.

Item 9 — *Changes in and Disagreements with Accountants on Accounting and Financial Disclosures*

None.

Item 9A — *Controls and Procedures*

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

Under the supervision and with the participation of our management, including our principal executive officer, principal financial officer and principal accounting officer, we conducted an evaluation of our disclosure controls and procedures, as such term is defined in Rules 13a-15(e) or 15d-15(e) of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). Based on this evaluation, our principal executive officer, principal financial officer and principal accounting officer concluded that our disclosure controls and procedures were effective as of the end of the period covered by this annual report on Form 10-K.

There have not been any changes in our internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the fourth quarter that have materially affected, or are reasonably likely to materially affected, or are reasonably likely to materially affect our internal control over financial reporting.

Item 9B — *Other Information*

Effective March 3, 2006, NRG entered into a restated employment agreement with David Crane, pursuant to which Mr. Crane will continue to serve as the Company's President and Chief Executive Officer. The initial term of the restated employment agreement will end on December 31, 2008, but the agreement provides for automatic extensions for additional successive one-year terms on the same terms and conditions, unless either party provides the other with notice to the contrary at least 90 days prior to the end of the initial term or any subsequent one-year term. The restated employment agreement provides for an initial annual base salary of $1,000,000. For each one-year period thereafter, Mr. Crane's base salary will be reviewed and may be increased by the Board. Beginning with the 2006 fiscal year, Mr. Crane is entitled to an annual bonus with a target amount of up to 100 percent of his base salary, based upon the achievement of criteria determined at the beginning of the fiscal year by the Board, with input from Mr. Crane, for that fiscal year. In addition, beginning with the 2006 fiscal year, Mr. Crane is entitled to a maximum annual bonus equal to up to an additional 100 percent of his base salary, based upon the achievement of criteria determined at the beginning of the fiscal year by the Board, with input from Mr. Crane, for that fiscal year. Mr. Crane is also eligible to participate in the Long Term Incentive Plan in accordance with its terms and is entitled to receive other customary fringe benefits generally available to the Company's executive employees. Mr. Crane is also entitled to certain severance benefits. Further details of Mr. Crane's employment package are set forth in the restated employment agreement attached as Exhibit 10.33 to this Form 10-K and incorporated herein by reference.

The Compensation Committee's and the Board of Director's approval of the Annual Incentive Plan Payout, or the AIP Payout, for each executive officer of NRG who is expected to be a named executive officer in NRG's Proxy Statement for the annual meeting of stockholders to be held on April 28, 2006 became final on March 7, 2006. The named executive officers include: David Crane, President and Chief Executive Officer;

Robert C. Flexon, Executive Vice President and Chief Financial Officer; Kevin Howell, Executive Vice President, Commercial Operations; John P. Brewster, Executive Vice President, International Operations and President, South Central Region; and Christine A. Jacobs, Vice President, Plant Operations. Effective January 3, 2006, the Board of Directors approved the 2006 Base Salary for Mr. Crane (as previously disclosed in a Form 8-K, filed January 5, 2006) and the Compensation Committee approved the 2006 Base Salary for the other named executive officers. The AIP Payout and the base salary for each named executive officer is set forth in the 2005 AIP Payout and 2006 Base Salary Table attached as Exhibit 10.34 to this Form 10-K and incorporated herein by reference.

On March 1, 2006, the Compensation Committee, duly authorized by the Board of Directors, approved 2006 performance targets for Mr. Crane, President and Chief Executive Officer, Mr. Flexon, Executive Vice President and Chief Financial Officer and the other named executive officers. Performance targets include EBITDA and free cash flow financial goals, as well as non-financial goals in the areas of safety, environmental, strategic development, staff development and individual performance objectives. As noted above, the Chief Executive Officer will have a target opportunity of 100 percent of base salary with an additional maximum opportunity of 100 percent of base salary. The Chief Financial Officer will have a target opportunity of 75 percent of base salary with an additional maximum opportunity of 75 percent of base salary. The remaining named executive officers will have a target opportunity ranging from 50 to 75 percent of base salary with an additional maximum opportunity ranging from 25 to 37.5 percent of base salary.

PART III

Item 10 — *Directors and Executive Officers of the Registrant*

NRG has adopted a code of ethics entitled "NRG Code of Conduct" that applies to directors, officers and employees, including the chief executive officer and senior financial officers of NRG Energy. It may be accessed through NRG's website at http://www.nrgenergy.com/investor/corpgov.htm. NRG also elects to disclose the information required by Form 8-K, Item 5.05, "Amendments to the registrant's code of ethics, or waiver of a provision of the code of ethics," through this website and such information will remain available on this website for at least a 12-month period. A copy of the "NRG Code of Conduct" is available in print to any shareholder who requests it.

Other information required by this Item will be incorporated by reference to the similarly named section of our definitive Proxy Statement for our 2006 Annual Meeting of Stockholders to be held April 28, 2006.

Item 11 — *Executive Compensation*

Other information required by this Item will be incorporated by reference to the similarly named section of our definitive Proxy Statement for our 2006 Annual Meeting of Stockholders to be held April 28, 2006.

Item 12 — *Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters*

Other information required by this Item will be incorporated by reference to the similarly named section of our definitive Proxy Statement for our 2006 Annual Meeting of Stockholders to be held April 28, 2006.

Item 13 — *Certain Relationships and Related Transactions*

Other information required by this Item will be incorporated by reference to the similarly named section of our definitive Proxy Statement for our 2006 Annual Meeting of Stockholders to be held April 28, 2006.

Item 14 — *Principal Accountant Fees and Services*

Other information required by this Item will be incorporated by reference to the similarly named section of our definitive Proxy Statement for our 2006 Annual Meeting of Stockholders to be held April 28, 2006.

PART IV

Item 15 — *Exhibits and Financial Statement Schedules*

(a) (1) Financial Statements

The following consolidated financial statements of NRG Energy and related notes thereto, together with the reports thereon of KPMG LLP are included herein:

Consolidated Statement of Operations — Year ended December 31, 2005 and the Year ended December 31, 2004 (Reorganized NRG)

Consolidated Balance Sheet — December 31, 2005 and December 31, 2004 (Reorganized NRG)

Consolidated Statement of Cash Flows — Year ended December 31, 2005 and the Year ended December 31, 2004 (Reorganized NRG)

Consolidated Statement of Stockholders' Equity/(Deficit) and Comprehensive Income/(Loss) — Year ended December 31, 2005 and the Year ended December 31, 2004 (Reorganized NRG)

Notes to Consolidated Financial Statements

The following consolidated financial statements of NRG Energy and related notes thereto, together with the reports thereon of PricewaterhouseCoopers LLP are included herein:

Consolidated Statements of Operations — The period December 6, 2003 to December 31, 2003 (Reorganized NRG) and the period January 1, 2003 to December 5, 2003 (Predecessor Company)

Consolidated Statements of Cash Flows — The period December 6, 2003 to December 31, 2003 (Reorganized NRG) and the period January 1, 2003 to December 5, 2003 (Predecessor Company)

Consolidated Statements of Stockholders' Equity/(Deficit) and Comprehensive Income/(Loss) — The period December 6, 2003 to December 31, 2003 (Reorganized NRG) and the period January 1, 2003 to December 5, 2003 (Predecessor Company)

Notes to Consolidated Financial Statements

(a) (2) Financial Statement Schedule

The following Consolidated Financial Statement Schedule of NRG Energy is filed as part of Item 15(d) of this report and should be read in conjunction with the Consolidated Financial Statements.

Report of Independent Registered Public Accounting Firm on Financial Statement Schedule.

Schedule II — Valuation and Qualifying Accounts

All other schedules for which provision is made in the applicable accounting regulation of the Securities and Exchange Commission are not required under the related instructions or are inapplicable, and therefore, have been omitted.

(a) (3) *Exhibits:* See Exhibit Index submitted as a separate section of this report.

(b) Exhibits

(c) Financial Statement Schedule

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Under the supervision and with the participation of our management, including our principal executive officer, principal financial officer and principal accounting officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation under the framework in Internal Control — Integrated Framework, our management concluded that our internal control over financial reporting was effective as of December 31, 2005.

Our management's assessment of the effectiveness of our internal control over financial reporting as of December 31, 2005 has been audited by KPMG LLP, our independent registered public accounting firm, as stated in its report which is included in this Form 10-K.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders
NRG Energy, Inc.:

We have audited management's assessment, included in the accompanying Management's Report on Internal Control over Financial Reporting, that NRG Energy, Inc. and subsidiaries maintained effective internal control over financial reporting as of December 31, 2005, based on "criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO)". NRG Energy, Inc.'s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that NRG Energy, Inc. and subsidiaries maintained effective internal control over financial reporting as of December 31, 2005, is fairly stated, in all material respects, based on "criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO)". Also, in our opinion, NRG Energy, Inc. and subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2005, based on "criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO)".

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet of NRG Energy, Inc. and subsidiaries as of December 31, 2005, and the related consolidated statements of operations, stockholders' equity/(deficit) and comprehensive income/(loss), and cash flows for the year then ended December 31, 2005, and our report dated March 7, 2006 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

KPMG LLP

Philadelphia, Pennsylvania
March 7, 2006

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders
NRG Energy, Inc.:

We have audited the accompanying consolidated balance sheets of NRG Energy, Inc. and subsidiaries as of December 31, 2005 and 2004, and the related consolidated statements of operations, stockholders' equity/(deficit) and comprehensive income/(loss), and cash flows for each of the years in the two year period ended December 31, 2005. In connection with our audits of the consolidated financial statements, we also have audited the financial statement schedule "Schedule II Valuation and Qualifying Accounts." These consolidated financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of NRG Energy, Inc. and subsidiaries as of December 31, 2005 and 2004, and the results of their operations and their cash flows for each of the years in the two year period ended December 31, 2005, in conformity with U.S. generally accepted accounting principles. Also in our opinion, the related financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of NRG Energy, Inc. and subsidiaries' internal control over financial reporting as of December 31, 2005, based on "criteria established in Internal Control — Integrated Framework, issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO)", and our report dated March 7, 2006 expressed an unqualified opinion on management's assessment of, and the effective operation of, internal control over financial reporting.

/s/ KPMG LLP

KPMG LLP

Philadelphia, Pennsylvania
March 7, 2006

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of NRG Energy, Inc.:

In our opinion, the accompanying consolidated statements of operations, cash flows and of stockholders' equity/(deficit) and comprehensive income/(loss) of NRG Energy, Inc. and its subsidiaries (Reorganized NRG) present fairly, in all material respects, the results of their operations and their cash flows for the period from December 6, 2003 to December 31, 2003 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). These standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

As discussed in Notes 1 and 2 to the consolidated financial statements, the United States Bankruptcy Court for the Southern District of New York confirmed the NRG Energy, Inc. Plan of Reorganization on November 24, 2003. Confirmation of the plan resulted in the discharge of all claims against the Company that arose before May 14, 2003 and substantially alters rights and interests of equity security holders as provided for in the plan. The NRG Energy, Inc. Plan of Reorganization was substantially consummated on December 5, 2003, and NRG Energy, Inc. emerged from bankruptcy. In connection with its emergence from bankruptcy, NRG Energy, Inc. adopted fresh start accounting as of December 5, 2003.

/s/ PRICEWATERHOUSECOOPERS LLP

PricewaterhouseCoopers LLP

Minneapolis, Minnesota
March 10, 2004, except as to Notes 6, 21, and 33, which are as of December 6, 2004

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholder of NRG Energy, Inc.:

In our opinion, the accompanying consolidated statement of operations, cash flows and of stockholders' equity/(deficit) and comprehensive income/(loss) of NRG Energy, Inc. and its subsidiaries (Predecessor Company) present fairly, in all material respects, the results of their operations and their cash flows for the period from January 1, 2003 to December 5, 2003 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). These standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Notes 1 and 2 to the consolidated financial statements, the Company filed a petition on May 14, 2003 with the United States Bankruptcy Court for the Southern District of New York for reorganization under the provisions of Chapter 11 of the Bankruptcy Code. NRG Energy, Inc.'s Plan of Reorganization was substantially consummated on December 5, 2003 and Reorganized NRG emerged from bankruptcy. In connection with its emergence from bankruptcy, the Company adopted fresh start accounting.

/s/ PRICEWATERHOUSECOOPERS LLP

PricewaterhouseCoopers LLP

Minneapolis, Minnesota
March 10, 2004, except as to Notes 6, 21, and 33, which are as of December 6, 2004

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	Reorganized NRG			Predecessor Company
	Year Ended December 31, 2005	Year Ended December 31, 2004	December 6, 2003 Through December 31, 2003	January 1, 2003 Through December 5, 2003
	(In millions, except per share amounts)			
Operating Revenues				
Revenues from majority-owned operations	$ 2,708	$ 2,348	$ 137	$ 1,798
Operating Costs and Expenses				
Cost of majority-owned operations	2,067	1,489	95	1,354
Depreciation and amortization	194	208	12	211
General, administrative and development	197	210	13	170
Other charges (credits)				
Corporate relocation charges	6	16	—	—
Reorganization items	—	(13)	2	198
Restructuring and impairment charges	6	45	—	237
Fresh start reporting adjustments	—	—	—	(4,220)
Legal settlement	—	—	—	463
Total operating costs and expenses	2,470	1,955	122	(1,587)
Operating Income	238	393	15	3,385
Other Income/(Expense)				
Equity in earnings of unconsolidated affiliates	104	160	14	171
Write downs and losses on sales of equity method investments	(31)	(16)	—	(147)
Other income, net	62	27	—	19
Refinancing expenses	(56)	(72)	—	—
Interest expense	(197)	(266)	(19)	(308)
Total other expense	(118)	(167)	(5)	(265)
Income From Continuing Operations Before Income Taxes	120	226	10	3,120
Income Tax Expense/(Benefit)	43	65	(1)	38
Income From Continuing Operations	77	161	11	3,082
Income/(Loss) on Discontinued Operations, net of Income Taxes	7	25	—	(316)
Net Income	84	186	11	2,766
Preference stock dividends	20	—	—	—
Income Available for Common Stockholders	$ 64	$ 186	$ 11	$ 2,766
Weighted Average Number of Common Shares Outstanding — Basic	85	100	100	—
Income From Continuing Operations per Weighted Average Common Share — Basic	$ 0.67	$ 1.61	$ 0.11	—
Income From Discontinued Operations per Weighted Average Common Share — Basic	0.09	0.25	—	—
Net Income per Weighted Average Common Share — Basic	$ 0.76	$ 1.86	$ 0.11	—
Weighted Average Number of Common Shares Outstanding — Diluted	85	100	100	—
Income From Continuing Operations per Weighted Average Common Share — Diluted	$ 0.66	$ 1.60	$ 0.11	—
Income From Discontinued Operations per Weighted Average Common Share — Diluted	0.09	0.25	—	—
Net Income per Weighted Average Common Shares — Diluted	$ 0.75	$ 1.85	$ 0.11	—

See notes to consolidated financial statements.

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	Reorganized NRG	
	December 31, 2005	December 31, 2004
	(In millions, except shares and par value)	
ASSETS		
Current Assets		
Cash and cash equivalents	$ 506	$ 1,104
Restricted cash	64	110
Accounts receivable-trade, less allowance for doubtful accounts of $2 and $1	280	270
Accounts receivable-affiliate	4	—
Current portion of notes receivable and capital lease	25	85
Property taxes receivable	43	37
Inventory	260	247
Derivative instruments valuation	404	80
Collateral on deposit in support of energy risk management activities	438	33
Deferred income taxes	4	—
Prepayments and other current assets	125	136
Current assets — held for sale	43	—
Current assets — discontinued operations	1	17
Total current assets	2,197	2,119
Property, Plant and Equipment, net	3,039	3,158
Other Assets		
Equity investments in affiliates	603	735
Notes receivable, less current portion — affiliates, net	103	124
Notes receivable and capital lease, less current portion, net	355	440
Intangible assets, net of accumulated amortization of $79 and $55	257	294
Derivative instruments valuation	22	42
Funded letter of credit	350	350
Deferred income tax	26	34
Other assets	125	111
Non-current assets — discontinued operations	354	457
Total other assets	2,195	2,587
Total Assets	$ 7,431	$ 7,864

See notes to consolidated financial statements.

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS — (Continued)

	Reorganized NRG	
	December 31, 2005	December 31, 2004
	(In millions, except shares and par value)	
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Current portion of long-term debt and capital leases	$ 101	$ 511
Accounts payable — trade	268	209
Accounts payable — affiliates	—	5
Derivative instruments valuation	692	17
Other bankruptcy settlement	3	6
Accrued expenses	82	57
Other current liabilities	95	109
Current liabilities — discontinued operations	115	173
Total current liabilities	1,356	1,087
Other Liabilities		
Long-term debt and capital leases	2,581	2,973
Deferred income taxes	135	169
Postretirement and other benefit obligations	125	116
Derivative instruments valuation	137	148
Out of market contracts	298	319
Other long-term obligations	81	71
Non-current liabilities — discontinued operations	240	288
Total non-current liabilities	3,597	4,084
Total liabilities	4,953	5,171
Minority interest	1	1
3.625% Convertible Perpetual Preferred Stock; $.01 par value; 250,000 shares issued and outstanding (at liquidation value of $250, net of issuance costs)	246	—
Commitments and Contingencies		
Stockholders' Equity		
4% Convertible Perpetual Preferred Stock; $.01 par value; 420,000 shares issued and outstanding at December 31, 2005 and 2004 (at liquidation value of $420, net of issuance costs)	406	406
Common stock; $.01 par value; 100,048,676 and 100,041,935 shares issued and 80,701,888 and 87,041,935 outstanding at December 31, 2005 and 2004, respectively	1	1
Additional paid-in capital	2,431	2,417
Retained earnings	261	197
Less treasury stock, at cost; 19,346,788 and 13,000,000 shares as of December 31, 2005 and 2004, respectively	(663)	(405)
Accumulated other comprehensive income/(loss)	(205)	76
Total stockholders' equity	2,231	2,692
Total Liabilities and Stockholders' Equity	$ 7,431	$ 7,864

See notes to consolidated financial statements.

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY/(DEFICIT) AND COMPREHENSIVE INCOME/(LOSS)

	Serial Preferred Stock	Serial Preferred Shares	Common Stock	Common Shares	Additional Paid-In Capital	Retained Earnings/ (Deficit)	Treasury Stock	Accumulated Other Comprehensive Income/(Loss)	Total Stockholders' Equity/ (Deficit)
					(In millions)				
Balances at December 31, 2002 (Predecessor Company)	$ —	—	$ —	—	$ 2,228	$ (2,829)	$ —	$ (95)	$ (696)
Net income						2,766			2,766
Foreign currency translation adjustments and other								128	128
Deferred unrealized loss on derivatives, net								(32)	(32)
Comprehensive income for the period from January 1, 2003 through December 5, 2003									2,862
Effects of reorganization					(2,228)	63		(1)	(2,166)
Issuance of common stock			1	100	2,403				2,404
Balances at December 5, 2003 (Predecessor Company)	$ —	—	$ 1	100	$ 2,403	$ —	$ —	$ —	$ 2,404
Net income						11			11
Foreign currency translation adjustments and other								23	23
Deferred unrealized loss on derivatives, net								(1)	(1)
Comprehensive income for the period from December 6, 2003 through December 31, 2003									33
Balances at December 31, 2003 (Reorganized NRG)	$ —	—	$ 1	100	$ 2,403	$ 11	$ —	$ 22	$ 2,437
Net income						186			186
Foreign currency translation adjustments and other								46	46
Deferred unrealized gain on derivatives, net								8	8
Comprehensive income for 2004									240
Equity based compensation					14				14
Issuance of preferred stock	406	0.4							406
Purchase of treasury stock				(13)			(405)		(405)
Balances at December 31, 2004 (Reorganized NRG)	$406	0.4	$ 1	87	$ 2,417	$ 197	$ (405)	$ 76	$ 2,692
Net income						84			84
Foreign currency translation adjustments and other								(72)	(72)
Deferred unrealized loss on derivatives, net								(203)	(203)
Minimum pension liability, net of $3 tax								(6)	(6)
Comprehensive loss for 2005									(197)
Equity based compensation					14				14
Preferred stock dividends						(20)			(20)
Purchase of treasury stock				(6)			(258)		(258)
Balances at December 31, 2005 (Reorganized NRG)	$406	0.4	$ 1	81	$ 2,431	$ 261	$ (663)	$ (205)	$ 2,231

See notes to consolidated financial statements.

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Reorganized NRG			Predecessor Company
	Year Ended December 31, 2005	Year Ended December 31, 2004	December 6, 2003 Through December 31, 2003	January 1, 2003 Through December 5, 2003
			(In millions)	
Cash Flows from Operating Activities				
Net income	$ 84	$ 186	$ 11	$ 2,766
Adjustments to reconcile net income to net cash provided by operating activities				
Distributions in excess of (less than) equity earnings of unconsolidated affiliates	(8)	(1)	2	(41)
Depreciation and amortization	195	215	13	257
Reserve for note and interest receivable	—	12	—	—
Amortization of financing costs and debt discount/(premium)	22	28	2	18
Write-off of deferred financing costs due to refinancings	(8)	42	—	—
Write downs and losses on sales of equity method investments	31	16	—	147
Deferred income taxes and investment tax credits	2	57	(3)	(2)
Unrealized (gains)/losses on derivatives	143	(74)	4	(35)
Minority interest	1	1	—	2
Amortization of intangible assets	17	52	(13)	—
Amortization of unearned equity compensations	12	14	—	—
Restructuring and impairment charges	6	45	—	408
Fresh start reporting adjustments	—	—	—	(3,895)
Loss on sale and disposal of assets	4	1	—	—
Gain on sale of discontinued operations	(6)	(23)	—	(186)
Gain on TermoRio settlement	(14)	—	—	—
Collateral deposit payments in support of energy risk management activities	(405)	(7)	(8)	—
Cash provided by (used in) changes in certain working capital items, net of effects from acquisitions and dispositions				
Accounts receivable, net	(8)	(52)	18	28
Xcel Energy settlement receivable	—	640	—	—
Inventory	(14)	(56)	11	14
Prepayments and other current assets	(35)	126	(71)	(37)
Accounts payable	57	50	(40)	649
Accrued expenses	(8)	(21)	(67)	217
Creditor pool obligation payments	—	(540)	—	—
Other current liabilities	(8)	(106)	(441)	(23)
Other assets and liabilities	8	40	(7)	(49)
Net Cash Provided (Used) by Operating Activities	68	645	(589)	238
Cash Flows from Investing Activities				
Proceeds from sale of discontinued operations	36	253	—	19
Proceeds from sale of investments	70	51	—	107
Proceeds from sale of turbines and other property, plant and equipment	9	4	—	71
Decrease/(increase) in restricted cash and trust funds	45	(27)	375	(266)
Decrease/(increase) in notes receivable	107	25	1	(2)
Deferred acquisition costs	(5)	—	—	—
Capital expenditures	(106)	(119)	(11)	(114)
Return of capital/(Investments) in projects	2	(3)	(2)	(1)
Net Cash Provided (Used) by Investing Activities	158	184	363	(186)
Cash Flows from Financing Activities				
Payment of dividends to preferred shareholders	(20)	—	—	—
Repayment of minority interest obligations	(4)	—	—	—
Accelerated share repurchase payment, net	(250)	—	—	—
Purchase of treasury stock	—	(405)	—	—
Issuance of 4% Preferred Stock, net	—	406	—	—
Issuance of 3.625% Preferred Stock, net	246	—	—	—
Proceeds from issuance of long-term debt, net	249	1,333	2,450	40
Deferred debt issuance costs	(46)	(26)	(75)	(19)
Funded letter of credit	—	(100)	(250)	—
Principal payments on short and long-term debt	(1,005)	(1,492)	(1,732)	(51)
Net Cash Provided (Used) by Financing Activities	(830)	(284)	393	(30)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	(2)	3	(14)	(22)
Change in Cash from Discontinued Operations	8	6	1	35
Net Increase/(Decrease) in Cash and Cash Equivalents	(598)	554	154	35
Cash and Cash Equivalents at Beginning of Period	1,104	550	396	361
Cash and Cash Equivalents at End of Period	$ 506	$ 1,104	$ 550	$ 396

See notes to consolidated financial statements.

Note 1 — Organization

General

We are a leading wholesale power generation company with a significant presence in many of the major competitive power markets in the United States. We are primarily engaged in the ownership and operation of power generation facilities, purchasing fuel and transportation services to support our power plant operations, and the marketing and trading of energy, capacity and related products in the competitive markets in which we operate.

Our facilities consist primarily of baseload, intermediate and peaking power generation facilities, and also include thermal energy production and energy resource recovery plants. The sale of capacity and power from baseload generation facilities accounts for the majority of our revenues and provides a stable source of cash flow. In addition, our diverse generation portfolio provides us with opportunities to capture additional revenues by selling power into our core regions during periods of peak demand, offering capacity or similar products to retail electric providers and others, and providing ancillary services to support system reliability.

On February 2, 2006, NRG completed the acquisition of Texas Genco, or the Acquisition. The purchase price of approximately $6.1 billion consisted of approximately $4.4 billion in cash and the issuance of approximately 35.4 million shares of NRG's common stock valued at $1.7 billion. This amount is subject to adjustment due to acquisition costs. The value of our common stock issued to the former direct and indirect owners of Texas Genco, or the Sellers, was based on our average stock price immediately before and after the closing date of February 2, 2006. The Acquisition includes the assumption of approximately $2.7 billion of Texas Genco debt. Texas Genco is now a wholly-owned subsidiary of NRG, and will be managed and accounted for as a new business segment to be referred to as NRG Texas.

We were formed in 1992 as the non-utility subsidiary of Northern States Power Company, or NSP, which was itself merged into New Century Energies, Inc. to form Xcel Energy, Inc., or Xcel Energy, in 2000. In 2002, a number of factors including the overall downturn in the power generation industry, triggered a series of credit rating downgrades which, in turn, precipitated a severe liquidity crisis at the Company. From May 14 to December 23, 2003, we and a number of our subsidiaries undertook a comprehensive reorganization and restructuring under chapter 11 of the United States Bankruptcy Code.

As part of our reorganization, Xcel Energy relinquished its ownership interest in us, and we became an independent public company. We no longer have any material affiliation or relationship with Xcel Energy. As part of our restructuring, on December 23, 2003, we used the proceeds of a new $1.25 billion offering of 8% second priority senior secured notes due 2013, and borrowings under a new $1.45 billion secured credit facility, to retire approximately $1.7 billion of project-level debt.

We were incorporated as a Delaware corporation on May 29, 1992. Our common stock is listed on the New York Stock Exchange under the symbol "NRG". Our headquarters and principal executive offices are located at 211 Carnegie Center, Princeton, New Jersey 08540. Our telephone number is (609) 524-4500. The address of our website is www.nrgenergy.com. Our recent annual reports, quarterly reports, current reports and other periodic filings are available free of charge through our website.

Note 2 — Summary of Significant Accounting Policies

Nature of Operations

We are a wholesale power generation company, primarily engaged in the ownership and operation of power generation facilities and the sale of energy, capacity and related products in the United States and internationally. We have a diverse portfolio of electric generation facilities in terms of geography, fuel type, and dispatch levels, which help mitigate risk. We seek to maximize operating income through the efficient procurement and management of fuel supplies and maintenance services, and the sale of energy, capacity and ancillary services into attractive spot, intermediate and long-term markets.

Principles of Consolidation and Basis of Presentation

Between May 14, 2003 and December 5, 2003, we operated as a debtor-in-possession under the supervision of the bankruptcy court. Our financial statements for reporting periods within that timeframe were prepared in accordance with the provisions of SOP 90-7.

For financial reporting purposes, close of business on December 5, 2003, represents the date of our emergence from bankruptcy. As used herein, the following terms refer to the Company and its operations:

"Predecessor Company"	The Company, pre-emergence from bankruptcy The Company's operations prior to December 6, 2003
"Reorganized NRG"	The Company, post-emergence from bankruptcy The Company's operations, December 6, 2003-December 31, 2005

In January 2003, the FASB issued FIN 46 which requires an enterprise's consolidated financial statements to include subsidiaries in which the enterprise has a controlling interest. In December 2003, the FASB published a revision to Interpretation 46, or FIN 46R, to clarify some of the provisions of FIN 46 and to exempt certain entities from its requirements. As required by SOP 90-7, we adopted FIN 46R as of the adoption of Fresh Start and consequently we have consolidated operations of hydropower facilities on the East Coast, Northbrook New York and Northbrook Energy. These operations have been sold during 2005 and classified as discontinued operations. Also see Note 6 for further discussion.

The consolidated financial statements include our accounts and operations and those of our subsidiaries in which we have a controlling interest. All significant intercompany transactions and balances have been eliminated in consolidation. Accounting policies for all of our operations are in accordance with accounting principles generally accepted in the United States of America. As discussed in Note 13, we have investments in partnerships, joint ventures and projects.

Fresh Start Reporting

In accordance with SOP 90-7, certain companies qualify for fresh start reporting in connection with their emergence from bankruptcy. Fresh start reporting is appropriate on the emergence from chapter 11 if the reorganization value of the assets of the emerging entity immediately before the date of confirmation is less than the total of all post-petition liabilities and allowed claims, and if the holders of existing voting shares immediately before confirmation receive less than 50 percent of the voting shares of the emerging entity. We met these requirements and adopted Fresh Start reporting resulting in the creation of a new reporting entity designated as Reorganized NRG.

The bankruptcy court issued a confirmation order approving our plan of reorganization on November 24, 2003. Under the requirements of SOP 90-7, the Fresh Start date is determined to be the confirmation date unless significant uncertainties exist regarding the effectiveness of the bankruptcy order. Our plan of reorganization required completion of the Xcel Energy settlement agreement prior to emergence from bankruptcy. The Xcel Energy settlement agreement was entered into on December 5, 2003. We believe this settlement agreement was a significant contingency and thus delayed the Fresh Start date until the Xcel Energy settlement agreement was finalized on December 5, 2003.

Under the requirements of Fresh Start, we adjusted our assets and liabilities, other than deferred income taxes, to their estimated fair values as of December 5, 2003. As a result of marking our assets and liabilities to their estimated fair values, we determined that there was a negative reorganization value that was reallocated back to our tangible and intangible assets. Deferred taxes were determined in accordance with SFAS 109. The net effect of all Fresh Start adjustments resulted in a gain of $3.9 billion (comprised of a $4.2 billion gain from continuing operations and a $0.3 billion loss from discontinued operations), which is reflected in the Predecessor Company's results for the period January 1, 2003 through December 5, 2003. The application of the Fresh Start provisions of SOP 90-7 created a new reporting entity having no retained earnings or accumulated deficit.

As part of the bankruptcy process we engaged an independent financial advisor to assist in the determination of our reorganized enterprise value. The fair value calculation was based on management's forecast of expected cash flows from our core assets. Management's forecast incorporated forward commodity market prices obtained from a third party consulting firm. A discounted cash flow calculation was used to develop the enterprise value of Reorganized NRG, determined in part by calculating the weighted average cost of capital of the Reorganized NRG. The Discounted Cash Flow, or DCF, valuation methodology equates the value of an asset or business to the present value of expected future economic benefits to be generated by that asset or business. The DCF methodology is a "forward looking" approach that discounts expected future economic benefits by a theoretical or observed discount rate. The independent financial advisor prepared a 30-year cash flow forecast using a discount rate of approximately 11%. The resulting reorganization enterprise value as included in the bankruptcy Disclosure Statement ranged from $5.5 billion to $5.7 billion. The independent financial advisor then subtracted our project-level debt and made several other adjustments to reflect the values of assets held for sale, excess cash and collateral requirements to estimate a range of Reorganized NRG equity value of between $2.2 billion and $2.6 billion.

In constructing our Fresh Start balance sheet upon our emergence from bankruptcy, we used a reorganization equity value of approximately $2.4 billion, as we believe this value to be the best indication of the value of the ownership distributed to the new equity owners. Our reorganization value of approximately $9.1 billion was determined by adding our reorganized equity value of $2.4 billion, $3.7 billion of interest bearing debt and our other liabilities of $3.0 billion. The reorganization value represents the fair value of an entity before liabilities and approximates the amount a willing buyer would pay for the assets of the entity immediately after restructuring. This value is consistent with the voting creditors and Court's approval of the Plan of Reorganization.

A separate plan of reorganization was filed for our Northeast Generating and South Central Generating entities that was confirmed by the bankruptcy court on November 25, 2003, and became effective on December 23, 2003, when the final conditions of the plan were completed. In connection with Fresh Start on December 5, 2003, we have accounted for these entities as if they had emerged from bankruptcy at the same time that we emerged, as we believe that we continued to maintain control over the Northeast Generating and South Central Generating facilities throughout the bankruptcy process.

Due to the adoption of Fresh Start upon our emergence from bankruptcy, the Reorganized NRG statement of operations and statement of cash flows have not been prepared on a consistent basis with the Predecessor Company's statement of operations and statement of cash flows and are therefore not comparable to these statements prior to the application of Fresh Start.

Cash and Cash Equivalents

Cash and cash equivalents include highly liquid investments (primarily commercial paper and money market accounts) with an original maturity of three months or less at the time of purchase.

Restricted Cash

Restricted cash consists primarily of funds held to satisfy the requirements of certain debt agreements and funds held within our projects that are restricted in their use. These funds are used to pay for current operating expenses and current debt service payments, per the restrictions of the debt agreements.

Inventory

Inventory is valued at the lower of weighted average cost or market and consists principally of fuel oil, coal, emission allowances and raw materials used to generate steam. Spare parts inventory is valued at weighted average cost, as we expect to recover these costs in the ordinary course of business. Sales of inventory are classified as an operating activity in the consolidated statements of cash flows.

Property, Plant and Equipment

Property, plant and equipment are stated at cost however impairment adjustments are recorded whenever events or changes in circumstances indicate carrying values may not be recoverable. On December 5, 2003, we recorded adjustments to the property, plant and equipment to reflect such items at fair value in accordance with Fresh Start reporting. A new cost basis was established with these adjustments. Significant additions or improvements extending asset lives are capitalized, while repairs and maintenance that do not improve or extend the life of the respective asset are charged to expense as incurred. Depreciation will be computed using the straight-line method over the following estimated useful lives:

Facilities and equipment	1-42 years
Office furnishings and equipment	2-10 years

The assets and related accumulated depreciation amounts are adjusted for asset retirements and disposals with the resulting gain or loss included in operations.

Asset Impairments

Long-lived assets that are held and used are reviewed for impairment whenever events or changes in circumstances indicate carrying values may not be recoverable. Such reviews are performed in accordance with SFAS 144. An impairment loss is recognized if the total future estimated undiscounted cash flows expected from an asset are less than its carrying value. An impairment charge is measured by the difference between an asset's carrying amount and fair value and included in operating costs and expenses in the statement of operations. Fair values are determined by a variety of valuation methods, including appraisals, sales prices of similar assets and present value techniques.

Investments accounted for by the equity method are reviewed for impairment in accordance with APB 18 which requires that a loss in value of an investment that is other than a temporary decline should be recognized. We identify and measure losses in value of equity investments based upon a comparison of fair value to carrying value.

Discontinued Operations

Long-lived assets are classified as discontinued operations when all of the required criteria specified in SFAS 144 are met. These criteria include, among others, existence of a qualified plan to dispose of an asset, an assessment that completion of a sale within one year is probable and approval of the appropriate level of management. Discontinued operations are reported at the lower of the asset's carrying amount or fair value less cost to sell.

Capitalized Interest

Interest incurred on funds borrowed to finance projects expected to require more than three months to complete is capitalized. Capitalization of interest is discontinued when the asset under construction is ready for its intended use or when a project is terminated or construction ceased. Capitalized interest was approximately $0.2 million, $3 million, $1 million, and $5 million for the years ended December 31, 2005 and

December 31, 2004, and the periods December 6, 2003 to December 31, 2003 and January 1, 2003 to December 5, 2003, respectively.

Capitalized Project Costs

Development costs and capitalized project costs include third party professional services, permits, and other costs that are incurred incidental to a particular project. Such costs are expensed as incurred until an acquisition agreement or letter of intent is signed, and our Board of Directors has approved the project. Additional costs incurred after this point are capitalized. When a project begins operations, previously capitalized project costs are reclassified to equity investments in affiliates or property, plant and equipment and amortized on a straight-line basis over the lesser of the life of the project's related assets or revenue contract period. Capitalized costs are charged to expense if a project is abandoned or management otherwise determines the costs to be unrecoverable.

Debt Issuance Costs

Debt issuance costs are capitalized and amortized as interest expense on a basis which approximates the effective interest method over the terms of the related debt.

Intangible Assets

Intangible assets represent contractual rights held by us. Intangible assets are amortized over their economic useful life and reviewed for impairment on a periodic basis.

Income Taxes

The Reorganized NRG's income tax provision for the years ended December 31, 2005 and December 31, 2004, and for the period December 6, 2003 through December 31, 2003 has been recorded on the basis that we and our U.S. subsidiaries reconsolidated for federal income tax purposes as of December 6, 2003. The Reorganized NRG is no longer owned by Xcel Energy and thus, no longer included in the Xcel Energy affiliated group. The change in ownership allows us to file a consolidated federal income tax return with our U.S. subsidiaries starting on December 6, 2003.

The Predecessor Company's income tax provision has been recorded on the basis that Xcel Energy has not included us in its consolidated federal income tax return following Xcel Energy's acquisition of our public shares on June 3, 2002. Since we and our U.S. subsidiaries will not be included in the Xcel Energy's consolidated tax group, each of our U.S. subsidiaries that is classified as a corporation for U.S. income tax purposes filed a separate federal income tax return for the period ended December 5, 2003.

Deferred income taxes are recognized for the tax consequences in future years of temporary differences between the tax basis of assets and liabilities and their financial reporting amounts at each year-end based on enacted tax laws and statutory tax rates applicable to the periods in which the differences are expected to affect taxable income. Income tax expense is the tax payable for the period and the change during the period in deferred tax assets and liabilities. A valuation allowance is recorded to reduce deferred tax assets to the amount more likely than not to be realized.

Revenue Recognition

We are primarily an electric generation company, operating a portfolio of majority-owned electric generating plants and certain plants in which our ownership interest is 50% or less which are accounted for under the equity method of accounting. In connection with our electric generation business, we also produce thermal energy for sale to customers, principally through steam and chilled water facilities. We also collect methane gas from landfill sites, which are used for the generation of electricity. In addition, we sell small amounts of natural gas and oil to third parties.

Energy. Both physical and financial transactions are entered into to optimize the financial performance of our generating facilities. Electric energy revenue is recognized upon transmission to the customer. We record gross revenues in regions where bilateral markets exist and physical delivery of electricity is common from our plants under the accrual method. In certain markets, which are operated and/or controlled by an ISO and in which we have entered into a netting agreement with the ISO, which results in our receiving a netted invoice, we have recorded purchased energy as an offset against revenues received upon the sale of such energy. Revenues derived from the buying and selling of electricity from an ISO and not sourced from our facilities are reported net.

Capacity. Capacity and ancillary revenue is recognized when contractually earned, and consists of revenues received from a third party at either the market or negotiated contract rates for making installed generation capacity available in order to satisfy system integrity and reliability requirements. We provide contract operations and maintenance services to some of our non-consolidated affiliates. Revenue is recognized as contract services are performed.

Revenue from Sales of Emission Allowances. During 2005, we began selling our excess SO_2 emission allowances. We record the sale of these allowances in Operating Revenues. The cost basis of these allowances, established upon the adoption of Fresh Start, is recorded in Operating Costs and Expenses. Beginning in 2006, we will actively manage our SO_2 emission allowances as well as fuels, and we will account for such asset optimization activity related to emission allowances and other fuel commodities under EITF 02-3, *"Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities."* As such, revenues and costs for the asset and optimization activities would be reflected on a net basis in the consolidated statement of operations.

Contract Amortization. At Fresh Start we recognized liabilities for power sales agreements related to the sale of electric capacity and energy in future periods where the fair value was determined to be significantly out of market as compared to market expectations. The liability is being amortized as an increase to revenue over the term of each underlying contract based on actual generation. The carrying amount of the unfavorable out-of-market power sales agreements at December 31, 2005 and 2004 was $298 million and $319 million, respectively. The estimated annual amortization of the out-of-market power sales agreements for each of the five succeeding years is expected to approximate $37 million in 2006, $28 million in 2007, $24 million in 2008, $24 million in 2009 and $20 million for 2010.

Disputed Revenues. Disputed revenues are not recorded in the financial statements until disputes are effectively resolved and collection is reasonably assured.

Derivative Financial Instruments

In January 2001, we adopted SFAS 133, as amended by SFAS 137, SFAS 138 and SFAS 149. SFAS 133, as amended, requires us to record all derivatives on the balance sheet at fair value. In some cases hedge accounting may apply. The criteria used to determine if hedge accounting treatment is appropriate are — a) the designation of the hedge to an underlying exposure, b) whether or not the overall risk is being reduced, and c) if there is correlation between the value of the derivative instrument and the underlying obligation. Formal documentation of the hedging relationship, the nature of the underlying risk, the risk management objective, and the means by which effectiveness will be assessed is created at the inception of the hedge. Changes in the fair value of non-hedge derivatives are immediately recognized in earnings. Changes in the fair value of derivatives accounted for as hedges are either recognized in earnings as an offset to the changes in the fair value of the related hedged assets, liabilities and firm commitments or for forecasted transactions, deferred and recorded as a component of accumulated other comprehensive income, or OCI, until the hedged transactions occur and are recognized in earnings. We primarily account for derivatives under SFAS 133, as amended, for as long-term power sales contracts, long-term gas purchase contracts and other energy related commodities and financial instruments used to mitigate variability in earnings due to fluctuations in spot market prices, hedge fuel requirements at generation facilities and to protect investments in fuel inventories. SFAS 133, as amended, also applies to interest rate swaps and foreign currency exchange rate contracts. The application of SFAS 133, as amended, results in increased volatility in earnings due to the recognition of unrealized gains and losses. In determining the fair value of these derivative/financial instruments we use estimates, various assumptions, judgment of management and when considered appropriate, third party experts in determining the fair value of these derivatives.

Foreign Currency Translation and Transaction Gains and Losses

The local currencies are generally the functional currency of our foreign operations. Foreign currency denominated assets and liabilities are translated at end-of-period rates of exchange. Revenues, expenses and cash flows are translated at weighted-average rates of exchange for the period. The resulting currency translation adjustments are accumulated and reported as a separate component of stockholders' equity and are not included in the determination of the results of operations. Foreign currency transaction gains or losses are reported in results of operations. We recognized foreign currency transaction gains (losses) of $(1) million, $2 million, $0.4 million, and $(20) million for the years ended December 31, 2005, December 31, 2004, and the periods December 6, 2003 to December 31, 2003 and January 1, 2003 to December 5, 2003, respectively.

Concentrations of Credit Risk

Financial instruments, which potentially subject us to concentrations of credit risk, consist primarily of cash, trust funds, accounts receivable, notes receivable and investments in debt securities. Cash accounts and trust funds are generally held in federally insured banks. Accounts receivable, notes receivable and derivative instruments are concentrated within entities engaged in the energy industry. These industry concentrations may impact our overall exposure to credit risk, either positively or negatively, in that the customers may be similarly affected by changes in economic, industry or other conditions. Receivables are generally not collateralized; however, we believe the credit risk posed by industry concentration is offset by the diversification and creditworthiness of our customer base.

Fair Value of Financial Instruments

The carrying amount of cash and cash equivalents, trust funds, receivables, accounts payables, and accrued liabilities approximate fair value because of the short maturity of these instruments. The carrying amounts of long-term receivables usually approximate fair value, as the effective rates for these instruments are comparable to market rates at year-end, including current portions. Any differences are disclosed in Note 5. The fair value of long-term debt is estimated based on quoted market prices for those instruments which are traded or on a present value method using current interest rates for similar instruments with equivalent credit quality.

Pensions

The determination of our obligation and expenses for pension benefits is dependent on the selection of certain assumptions. These assumptions determined by management include the discount rate, the expected rate of return on plan assets and the rate of future compensation increases. Our actuarial consultants use assumptions for such items as retirement age. The assumptions used may differ materially from actual results, which may result in a significant impact to the amount of pension obligation or expense recorded by us.

Stock Based Compensation

During the fourth quarter of 2003, in accordance with SFAS Statement No. 148, *"Accounting for Stock-Based Compensation — Transition and Disclosure"* we adopted SFAS 123 under the prospective transition method which requires the application of the recognition provisions to all employee awards granted, modified, or settled after the beginning of the fiscal year in which the recognition provisions are first applied. As a result, we applied the fair value recognition provisions of SFAS 123 as of January 1, 2003. We recognize compensation expense on a graded vesting basis for non-qualified stock option grants issued under the Long-Term Incentive Plan. The Black-Scholes option-pricing model is used for all non-qualified stock options. We recognize compensation expense on a straight-line basis over the applicable vesting period for restricted stock units (RSUs) and performance units (PUs). We use our common stock price on the date of grant as the fair value of the RSUs, while the fair value of the PU's is estimated on the date of grant using the Monte Carlo valuation model. In January 2006, we will adopt SFAS 123(R) under a modified version of prospective application as discussed below in *Recent Accounting Pronouncements.*

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements, disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from these estimates.

In recording transactions and balances resulting from business operations, we use estimates based on the best information available. Estimates are used for such items as plant depreciable lives, tax provisions, uncollectible accounts, actuarially determined benefit costs, and the valuation of long-term energy commodities contracts and environmental liabilities, and legal costs incurred in connection with recorded loss contingencies, among others. In addition, estimates are used to test long-lived assets for impairment and to determine fair value of impaired assets. As better information becomes available (or actual amounts are determinable), the recorded estimates are revised. Consequently, operating results can be affected by revisions to prior accounting estimates.

Reclassifications

Certain prior-year amounts have been reclassified for comparative purposes. These reclassifications had no effect on our net income or total stockholders' equity as previously reported.

Recent Accounting Developments

During the period, the FASB issued FIN 47 to clarify the term "conditional asset retirement obligation" as used in SFAS 143 governing the application of Asset Retirement Obligations. SFAS 143 refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. The obligation to perform the asset retirement activity is unconditional but there may remain some uncertainty as to the timing and/or method of settlement. Accordingly, an entity is required to recognize a liability for the fair value of a conditional asset retirement obligation if the fair value of the liability can be reasonably estimated. The fair value of a liability for the conditional asset retirement obligation should be recognized when incurred — generally upon acquisition, construction, or development and/or through the normal operation of the asset. SFAS 143 acknowledges that in some cases, sufficient information may not be available to reasonably estimate the fair value of an asset retirement obligation. FIN 47 clarifies when the company would have sufficient information to reasonably estimate the fair value of an asset retirement obligation. FIN 47 is effective for fiscal years ending after December 15, 2005. This guidance does not materially affect our consolidated financial position, results of operations or statement of cash flows.

Also during the period, the SEC issued Staff Accounting Bulletin 107, or SAB 107, which addresses the application of SFAS 123(R). SAB 107 was issued to assist registrants by simplifying some of the implementation challenges of SFAS 123(R) while enhancing the information that investors receive. SAB 107 creates a framework that is premised on two overarching themes — considerable judgment will be required by preparers to successfully implement SFAS 123(R), specifically when valuing employee stock options, and that reasonable individuals, acting in good faith, may conclude differently on the fair value of employee stock options. Accordingly, situations in which there is only one acceptable fair value estimate are expected to be rare. In addition, the SEC extended the adoption date to registrants for the implementation of SFAS 123(R) and SAB 107 so that they may implement this guidance for their fiscal year which begins after September 15, 2005. We will adopt SFAS 123(R) and SAB 107 on January 1, 2006 under a modified version of prospective application, or the modified prospective application. Under modified prospective application, we will apply the provisions of SFAS 123(R) to new awards and to awards modified, repurchased, or cancelled after the required effective date. In addition to applying a forfeiture rate to new awards, we are required to apply a forfeiture rate to existing awards and, if material, eliminate from balance sheet amounts and recognize in income as the cumulative effect of a change in accounting principle as of the required effective date. This guidance will not materially affect our consolidated financial position, results of operations or statement of cash flows.

Subsequent to release of SFAS 123R, the FASB issued Staff Position No. FAS 123R-3, *"Transition Election Related to Accounting for the Tax Effects of Share-Based Payment Awards"*, or FSP FAS 123R-3, on November 10, 2005. FSP FAS 123R-3 provides a one-time election related to the accounting for the tax benefits from share-based compensation cost since the adoption of FAS 123, and allows for purposes of calculating current tax expense, the aggregation of tax benefits recognized for share-based compensation in excess of financial statement tax benefits since adoption of FAS 123 in lieu of the award-by-award basis prescribed by SFAS 123R. We are currently evaluating the impact of this election, but do not expect this guidance to materially affect our consolidated financial position, results of operations or statement of cash flows.

On March 17, 2005, the Emerging Issues Task Force, or EITF, issued EITF No. 04-6 *"Accounting for Stripping Costs Incurred during Production in the Mining Industry"*, or EITF 04-6. EITF 04-6 provides that costs incurred to remove overburden and waste material to access coal seams, or stripping costs, during the production phase of a mine are variable production costs that should be included in the costs of the inventory produced during the period that the stripping costs are incurred. EITF 04-6 is effective for the first reporting period in fiscal years beginning after December 15, 2005. Our MIBRAG equity investment is a 50% interest in a mining company, which will be negatively affected by this pronouncement. Currently, MIBRAG has an asset totaling approximately € 157 million, approximately $185 million, representing the stripping costs incurred during production as of December 31, 2005. The adoption of EITF 04-6 will not have a material impact on our consolidated results of operations, but will have a material impact on our consolidated financial position. Following adoption on January 1, 2006, our investment in MIBRAG will be reduced by 50% of the above mentioned asset, approximately $93 million, with an offsetting charge to retained earnings.

Also during the period, the FASB issued SFAS No. 154 *"Accounting Changes and Error Corrections — a replacement of APB Opinion No. 20 and FASB Statement No. 3*, or SFAS 154. This Statement replaces APB Opinion No. 20, *"Accounting Changes"*, or APB 20, and FASB Statement No. 3, *"Reporting Accounting Changes in Interim Financial Statements"*, and changes the requirements for the accounting for and reporting of a change in accounting principle. This Statement applies to all voluntary changes in accounting principle. It also applies to changes required by an accounting pronouncement in the unusual instance that the pronouncement does not include specific transition provisions. When a pronouncement includes specific transition provisions, those provisions should be followed. APB 20 previously required that most voluntary changes in accounting principle be recognized by including in net income of the period of the change the cumulative effect of changing to the new accounting principle. This Statement requires retrospective application to prior periods' financial statements of changes in accounting principle for direct effects of the change, unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change, and redefines restatement as the revising of previously issued financial statements to reflect the correction of an error. This Statement shall be effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005.

On July 12, 2005, the FASB issued Staff Position APB 18-1, *"Accounting by an Investor for Its Proportionate Share of Accumulated Other Comprehensive Income of an Investee Accounted for under the Equity Method in Accordance with APB Opinion No. 18 upon a Loss of Significant Influence"*, or FSP APB 18-1. This guidance clarifies the application of paragraph 121 of SFAS No. 130, *"Reporting Comprehensive Income"*, or SFAS 130, and clarifies that the company's proportionate share of an investee's equity adjustments for OCI should be offset against the carrying value of the investment at the time significant influence is lost. To the extent that the offset results in a carrying value of the investment that is less than zero, an investor should (a) reduce the carrying value of the investment to zero and (b) record the remaining balance in income. The guidance in FSP APB 18-1 is effective as of the first reporting period after July 12, 2005. Currently, this guidance does not materially affect our consolidated financial position, results of operations or statement of cash flows.

On June 29, 2005, the EITF issued EITF Issue No. 04-5, *"Determining Whether a General Partner, or the General Partners as a Group, Controls a Limited Partnership or Similar Entity When the Limited Partners Have Certain Rights"*, or EITF 04-5. EITF 04-5 provides a framework for addressing when a general partner controls a limited partnership when the limited partners have certain rights. EITF 04-5's scope excludes a number of investment types, including limited partnerships entities that are not variable interest entities under FIN 46R, and investments accounted for under the pro rata method of consolidation. The guidance in EITF 04-5 is effective immediately to general partners of all new limited partnerships formed and for existing limited partnerships for which the partnership agreements are modified. For general partners in all other limited partnerships, the guidance in EITF 04-5 is effective no later than the beginning of the first reporting period in fiscal years beginning after December 15, 2005. Currently, this guidance will not materially affect our consolidated financial position, results of operations or statement of cash flows.

On June 16, 2005, the EITF issued EITF Issue No. 05-5, *"Accounting for Early Retirement or Postemployment Programs with Specific Features (Such As Terms Specified in Altersteilzeit Early Retirement Arrangements)"*, or EITF 05-5. EITF 05-5 provides guidance on the accounting for early retirement or postemployment programs with specific features, and specifically the terms of Altersteilzeit early retirement arrangements. The Altersteilzeit (ATZ) arrangement is a voluntary early retirement program in Germany designed to create an incentive for employees, within a certain age group, to transition from employment into retirement before their legal retirement age. If certain criteria are met by the employer, the German government provides to the employer a subsidy for bonuses paid to the employee and the additional contributions paid by the employer into the German government pension scheme under an ATZ arrangement for a maximum of six years. The Task Force reached a consensus that the employer should recognize the government subsidy when it meets the necessary criteria and is entitled to the subsidy. The Task Force also reached a consensus that payments made by the employer relative to the bonus feature and the additional contributions into the German government pension scheme (collectively, the additional compensation) should be accounted for as a post-employment benefit under SFAS 112, *Employers' Accounting for Post-employment Benefits*, which prescribes than an entity should recognize the additional compensation over the period from the point at which the employee signs the ATZ contract until the end of the active service period. The guidance of EITF 05-5 is effective no later than the beginning of the first reporting period in fiscal years beginning after December 15, 2005. We are currently evaluating the impact of this election, but do not expect this guidance to materially affect our consolidated financial position, results of operations or statement of cash flows.

Note 3 — Emergence from Bankruptcy and Fresh Start Reporting

In accordance with the requirements of SOP 90-7, we determined the reorganization value of NRG and subsidiaries emerging from bankruptcy to be approximately $9.1 billion. Reorganization value generally approximates fair value of the entity before considering liabilities and approximates the amount a willing buyer would pay for the assets of the entity immediately after the restructuring. Several methods are used to determine the reorganization value; however, generally it is determined by discounting future cash flows for the reconstituted business that will emerge from chapter 11 bankruptcy. Our approach was consistent in that our independent financial advisor's estimated reorganization enterprise value of our ongoing projects used a discounted cash flow approach.

We allocated the reorganization value of $9.1 billion to our assets in conformity with the procedures specified by SFAS 141. We used a third party to complete an independent appraisal of our tangible assets, equity investments and intangible assets and contracts. In completing the fair value allocation our assets were calculated to be greater than the reorganization value. As a result, we reallocated the negative reorganization value to our tangible and intangible assets in accordance with SFAS 141. In preparing our balance sheet we also recorded each liability existing at the plan confirmation date, other than deferred taxes, at the present value of amounts to be paid determined at appropriate current interest rates. Deferred taxes were reported in conformity with generally accepted accounting principles under SFAS 109. Our equity was recorded at approximately $2.4 billion representing a price per share of $24.04 for the issuance of 100 million shares of common stock upon emergence from bankruptcy. We pushed down the effects of fresh start reporting to all of our subsidiaries.

In constructing our Fresh Start balance sheet using our reorganization value upon our emergence from bankruptcy, we used a reorganization equity value of approximately $2.4 billion, as we believe this value to be the best indication of the value of the ownership distributed to the new equity owners. Accordingly, our reorganization value of $9.1 billion was determined by adding our reorganized equity value of $2.4 billion, $3.7 billion of interest bearing debt and our other liabilities of $3.0 billion. This value is consistent with the voting creditors and Court's approval of the Plan of Reorganization.

The determination of the enterprise value and the allocations to the underlying assets and liabilities were based on a number of estimates and assumptions, which are inherently subject to significant uncertainties and contingencies.

We recorded approximately $3.9 billion of net reorganization income (comprised of a $4.2 billion gain from continuing operations and a $0.3 billion loss from discontinued operations) in the Predecessor Company's statement of operations for 2003, which includes the gain on the restructuring of debt and equity and the discharge of obligations subject to compromise for less than recorded amounts, as well as adjustments to the historical carrying values of our assets and liabilities to fair market value.

Due to the adoption of Fresh Start as of December 5, 2003, the Reorganized NRG statement of operations and statement of cash flows have not been prepared on a consistent basis with the Predecessor Company's financial statements and are not comparable in certain respects to the financial statements prior to the application of Fresh Start. The accompanying Consolidated Financial Statements have been prepared to distinguish between Reorganized NRG and the Predecessor Company.

	Company December 5, 2003	Debt Discharge and Exchange of Stock	Fresh Start Adjustments	Consolidation	NRG December 6, 2003
		(In millions)			
Current Assets	$ 1,718	$ 614	$ 4	$ 6	$ 2,342
Non-current Assets	8,172	(155)	(1,233)	41	6,825
Total Assets	$ 9,890	$ 459	$ (1,229)	$ 47	$ 9,167
Current Liabilities	2,190	999	1,187	1	4,377
Non-current Liabilities	9,458	(6,270)	(848)	46	2,386
Total Liabilities	11,648	(5,271)	339	47	6,763
Stockholders Equity	(1,758)	2,404	1,758	—	2,404
Total Liabilities and Stockholders Equity	$ 9,890	$ (2,867)	$ 2,097	$ 47	$ 9,167

APB 18 requires us to effectively push down the effects of Fresh Start reporting to our unconsolidated equity method investments and to recognize an adjustment to our share of the earnings or losses of an investee as if the investee was a consolidated subsidiary. As a result of pushing down the impact of Fresh Start to our West Coast Power affiliate we determined that a contract based intangible asset with a one year remaining life, consisting of the value of West Coast Power's California Department of Water Resources energy sales contract, must be established and recognized as a basis adjustment to our share of the future earnings generated by West Coast Power. This adjustment reduced our equity earnings in the amount of approximately $10 million per month during 2004 until the contract expired in December 2004.

Note 4 — Debtors' Statements

As stated above, we and certain of our subsidiaries filed voluntary petitions for reorganization under chapter 11 of the Bankruptcy Code during 2003. On December 5, 2003, we and five of our subsidiaries emerged from bankruptcy. As of the respective bankruptcy filing dates, the debtors' financial records were closed for the pre-petition period. As required by SOP 90-7, below are the condensed combined financial statements of our remaining debtors since the date of the bankruptcy filings, or the Debtors' Statements.

The Debtors' Statements consist of the following wholly-owned consolidated entities which remained in bankruptcy as of December 6, 2003: Arthur Kill Power LLC, Astoria Gas Turbine Power LLC, Berrians I Gas Turbine Power, LLC, Big Cajun II Unit 4 LLC, Connecticut Jet Power LLC, Devon Power LLC, Dunkirk Power LLC, Huntley Power LLC, Louisiana Generating LLC, LSP-Nelson Energy LLC, Middletown Power LLC, Montville Power LLC, Northeast Generation Holding LLC, Norwalk Power LLC, NRG Central US LLC, NRG Eastern LLC, NRG McClain LLC, NRG Nelson Energy LLC, NRG New Roads Holdings LLC, NRG Northeast Generating LLC, NRG South Central Generating LLC, Oswego Harbor Power LLC, Somerset Power LLC, and South Central Generation Holding LLC. As of December 31, 2005, there were no entities remaining in bankruptcy.

Debtors' Condensed Combined Statement of Operations

	For the Period May 15, 2003 - December 5, 2003
	(In millions)
Operating revenue	$ 731
Operating costs and expenses	(620)
Fresh start reporting adjustments — asset write-downs, net	(1,244)
Reorganization items	(27)
Restructuring and impairment charges	(23)
Operating loss	(1,183)
Other expense	(161)
Net loss	$ (1,344)

Debtors' Condensed Combined Statement of Cash Flows

	For the Period May 15, 2003 December 5, 2003
	(In millions)
Net cash provided by operating activities	$ 66
Net cash used by investing activities	(73)
Net cash used by financing activities	—
Net increase in cash and cash equivalents	(7)
Cash and cash equivalents at beginning of period	23
Cash and cash equivalents at end of period	$ 16

Note 5 — Financial Instruments

The estimated fair values of our recorded financial instruments are as follows:

	Reorganized NRG			
	December 31, 2005		December 31, 2004	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In millions)			
Cash and cash equivalents	$ 506	$ 506	$ 1,104	$ 1,104
Restricted cash	64	64	110	110
Trust fund investments	20	20	20	20
Unfunded letters of credit and surety bonds	—	13	—	21
Notes receivable, including current portion	483	494	649	662
Long-term debt, including current portion	2,682	2,809	3,484	3,624

For cash and cash equivalents and restricted cash, the carrying amount approximates fair value because of the short-term maturity of those instruments. Trust funds investments are comprised of various U.S. debt securities carried at fair market value. Unfunded letters of credit and surety bonds are off balance sheet and are short term by nature. Because of their short-term characteristics, their balance approximates fair value.

The fair value of notes receivable is based on expected future cash flows discounted at market interest rates. The fair value of long-term debt is estimated based on quoted market prices for those instruments which are traded or on a present value method using current interest rates for similar instruments with equivalent credit quality.

Note 6 — Discontinued Operations

We have classified certain business operations, and gains/(losses) recognized on sale, as discontinued operations for projects that were sold or have met the required criteria for such classification. The financial results for all of these businesses have been accounted for as discontinued operations. Accordingly, current period operating results and prior periods have been restated to report the operations as discontinued. We have also classified certain assets as held for sale as management has committed to selling certain long lived assets within the next year. This classification does not affect prior period operating results.

SFAS 144 requires that discontinued operations be valued on an asset-by-asset basis at the lower of carrying amount or fair value less costs to sell. In applying those provisions our management considered cash flow analyses, bids and offers related to those assets and businesses. This amount is included in income/(loss) on discontinued operations, net of income taxes in the accompanying Statement of Operations. In accordance with the provisions of SFAS 144, assets held for sale will not be depreciated commencing with their classification as such.

The assets and liabilities of the discontinued operations are reported in the December 31, 2005 and 2004 balance sheets as discontinued operations. The major classes of assets and liabilities are presented by geographic area in the following table.

	Reorganized NRG	
	December 31, 2005	December 31, 2004
	Wholesale Power Generation	
	Other North America	
	Consists of Audrain	Consists of McClain, Northbrook New York, Northbrook Energy and Audrain
	(In millions)	
Cash and cash equivalents	$ —	$ 8
Restricted cash	—	5
Receivables, net	—	2
Inventory	1	1
Other current assets	—	1
	—	—
Current assets — discontinued operations	1	17
Property, plant and equipment, net	114	217
Notes Receivable	240	240
Non-current assets — discontinued operations	354	457
Current portion of long-term debt	—	1
Accounts payable — trade	—	1
Other current liabilities	115	171
Current liabilities — discontinued operations	115	173
Long-term debt	240	281
Minority interest	—	6
Other non-current liabilities	—	1
Non-current liabilities — discontinued operations	240	288

The following table summarizes our discontinued operations for all periods presented in our consolidated financial statements:

Project	Segment	Initial Discontinued Operations Treatment Date	Disposal Date
Killingholme	Other International	Fourth Quarter 2002	First Quarter 2003
NLGI	Alternative Energy	Second Quarter 2003	Second Quarter 2003
TERI	Non-Generation	Third Quarter 2003	Third Quarter 2003
McClain	Other North America	Third Quarter 2003	Third Quarter 2004
NEO Corporation (NEO Fort Smith LLC, NEO Woodville LLC, NEO Phoenix LLC)	Alternative Energy	Fourth Quarter 2003	Fourth Quarter 2003
Cahua and Energia Pacasmayo	Other International	Fourth Quarter 2003	Fourth Quarter 2003
PERC	Other North America	First Quarter 2004	Second Quarter 2004
Cobee	Other International	First Quarter 2004	Second Quarter 2004
Hsin Yu	Other International	Second Quarter 2004	Second Quarter 2004
LSP Energy (Batesville)	Other North America	Second Quarter 2004	Third Quarter 2004
NEO Corporation (NEO Nashville LLC, NEO Hackensack LLC, NEO Prima Deshecha LLC and NEO Tajiguas LLC)	Alternative Energy	Third Quarter 2004	Third Quarter 2004
Northbrook New York and Northbrook Energy	Other North America	Third Quarter 2005	Third Quarter 2005
Audrain	Other North America	Fourth Quarter 2005	Second Quarter 2006

Summarized results of operations were as follows:

Description	Reorganized NRG			Predecessor Company
	Year Ended December 31, 2005	Year Ended December 31, 2004	For the Period December 6 - December 31, 2003	For the Period January 1 - December 5, 2003
	(In millions)			
Operating revenues	$ 15	$ 122	$ 20	$ 263
Operating costs and other expenses	13	119	20	753
Pre-tax income/(loss) from operations of discontinued components	2	3	—	(490)
Income tax expense/(benefit)	1	—	—	(22)
Income/(loss) from operations of discontinued components	1	3	—	(468)
Disposal of discontinued components — pre-tax gain (net)	13	30	—	152
Income tax expense/(benefit)	7	8	—	—
Disposal of discontinued components — gain (net)	6	22	—	152
Income/(loss) on discontinued operations, net of income taxes	$ 7	$ 25	$ —	$ (316)

Operating costs and other expenses for 2005 shown in the table above include the impairment of Audrain's fixed assets and consequent reduction in the estimated liability by approximately $57 million, offsetting each other with no impact to Audrain's results. Due to the sale of our Audrain facility to AmerenUE for $115 million, the fixed asset was impaired to its fair value. Based on the agreement with CSFB, CSFB will receive only $115 million, reducing the corresponding estimated liability.

Operating costs and other expenses for 2004 include asset impairment charges of approximately $0.2 million. Operating costs and other expenses for 2003 include asset impairment charges of approximately $226 million, comprised of approximately $101 million for McClain, $24 million for NLGI and $101 for Audrain. The pre-tax gain or loss on disposals of discontinued components consist of the following:

		Reorganized NRG			Predecessor Company
Project	Segment	Year Ended December 31, 2005	Year Ended December 31, 2004	For the Period December 6 - December 31, 2003	For the Period January 1 - December 5, 2003
			(In millions)		
Northbrook Energy, Northbrook New York ..	Other North America	$ 12	$ —	$ —	$ —
McClain	Other North America	—	(3)	—	—
PERC	Other North America	—	3	—	—
Cobee	Other International	—	3	—	—
LSP Energy — Batesville ..	Other North America	—	11	—	—
Hsin Yu	Other International	—	10	—	—
NEO Nashville, Hackensack, Prima Deshecha, Tajiguas	Alternative Energy	—	6	—	—
Killingholme	Other International	—	—	—	191
TERI	Non-Generation	—	—	—	1
Cahua and Energia Pacasmayo	Other International	—	—	—	(37)
Others		—	—	—	(3)
Total gain on disposal of discontinued components — pre-tax ...		$ 12	$ 30	$ —	$ 152

Audrain Generating LLC — On December 8, 2005 NRG entered into an Asset Purchase and Sale Agreement to sell all the assets of NRG Audrain Generating LLC, or Audrain, to AmerenUE, a subsidiary of Ameren Corporation. The purchase price is $115 million, subject to customary purchase price adjustments. The transaction is expected to close during the second quarter of 2006. The sale is subject to customary approvals, including Federal Energy Regulatory Commission, Missouri Public Utilities Commission, Illinois Commerce Commission, and Hart-Scott-Rodino review. We expect to record a gain of approximately $15 million at closing.

Northbrook New York LLC and Northbrook Energy LLC — On August 11, 2005, we completed the sale of Northbrook New York LLC and Northbrook Energy LLC. In exchange for the sale, we received net cash proceeds of $36 million and paid off Northbrook New York LLC's third party debt of $17 million. We recognized a net pre-tax gain of $12 million in the third quarter of 2005.

McClain — We reviewed the recoverability of our McClain assets pursuant to SFAS No. 144 and recorded a charge of $101 million in the second quarter of 2003. On August 14, 2003, NRG's Board of Directors approved a plan to sell its 77% interest in McClain Generating Station, a 520-MW combined-cycle, natural gas-fired facility located in New Castle, Oklahoma. On July 9, 2004, NRG McClain completed the sale of its 77% interest in the McClain Generating Station to Oklahoma Gas & Electric Company. The Oklahoma Municipal Power Authority will continue to own the remaining 23% interest in the facility. The proceeds of $160 million from the sale were used to repay outstanding project debt under the secured term loan and working capital facility. A loss of $3 million was recognized as of June 30, 2004 based upon the final terms of the sale.

Penobscot Energy Recovery Company (PERC) — During the first quarter of 2004, we received board authorization to proceed with the sale of our interest in PERC to SET PERC Investment LLC which reached financial closing in April 2004. Upon completion of the transaction, we received net proceeds of $18 million, resulting in a gain of approximately $3 million.

Cobee — During the first quarter of 2004, we entered into an agreement for the sale of our interest in our Cobee project to Globeleq Holdings Limited, which reached financial closing in April 2004. Upon completion of the transaction, we received net proceeds of approximately $50 million, resulting in a gain of $3 million.

LSP Energy — Batesville — On August 24, 2004, we completed the sale of our 100 percent interest in an 837-megawatt generating plant in Batesville, Mississippi to CEP Batesville Acquisition, LLC. CEP Batesville Acquisition, LLC assumed approximately $300 million of outstanding project debt. The transaction resulted in the elimination of $289 million in consolidated debt from NRG Energy's balance sheet. In exchange for the sale, we received cash proceeds of $28 million. We recorded a gain of $11 million in 2004.

Hsin Yu — During the second quarter of 2004, we entered into an agreement for the sale of our interest in our Hsin Yu project to a minority interest shareholder, Asia Pacific Energy Development Company Ltd., which reached financial closing in May 2004. Completion of the transaction resulted in a gain of approximately $10 million, resulting from our negative equity in the project. In addition, although we have no continuing involvement in the project, we retained the prospect of receiving an additional $1 million in additional proceeds upon final closing of Phase II of the project.

NEO Corporation — In November 2003, we entered into a settlement agreement with Cambrian where we agreed to transfer our 100% interest in three gasco projects (NEO Ft. Smith, NEO Phoenix and NEO Woodville). During the third quarter of 2004, we completed the sale of four wholly-owned entities — NEO Nashville LLC, NEO Hackensack LLC, NEO Prima Deshecha LLC and NEO Tajiguas LLC, as well as the sale of several NEO investments — Four Hills LLC, Minnesota Methane II LLC, NEO Montauk Genco LLC and NEO Montauk Gasco LLC to Algonquin Power of Canada. Upon completion of the transaction, we received cash proceeds of $6 million, resulting in a $6 million gain associated with the four wholly-owned entities sold and received cash proceeds of $6 million resulting in a loss of approximately $4 million attributable to the equity investments sold. The sale of these equity investments do not qualify for reporting purposes as discontinued operations.

Killingholme — In January 2003, we completed the sale of our interest in the Killingholme project to our lenders for a nominal value and forgiveness of outstanding debt with a carrying value of approximately $360 million at December 31, 2002. The sale of our interest in the Killingholme project and the release of debt obligations resulted in a gain on sale in the first quarter of 2003 of approximately $191 million. The gain results from the write-down of the project's assets in the third quarter of 2002 below the carrying value of the related debt.

NLGI — During the quarter ended March 31, 2003, we recorded impairment charges of $24 million related to subsidiaries of NLGI and a charge of $14 million to write off our 50% investment in Minnesota Methane, LLC. Through April 30, 2003, NRG Energy and NLGI failed to make certain payments causing a default under NLGI's term loan agreements. In May 2003, the project lenders to the wholly-owned subsidiaries of NLGI and Minnesota Methane LLC foreclosed on our membership interest in the NLGI subsidiaries and our equity interest in Minnesota Methane LLC. There was no material gain or loss recognized as a result of the foreclosure.

TERI — In September 2003, we completed the sale of TERI, a biomass waste-fuel power plant located in Florida and a wood processing facility located in Georgia, to DG Telogia Power, LLC. The sale resulted in net proceeds of approximately $1 million. We entered into an agreement to sell the wood processing facility on behalf of DG Telogia Power, LLC. This sale was completed during fourth quarter 2003 and we received cash consideration of approximately $1 million, resulting in a net gain on sale of approximately $1 million.

Cahua and Energia Pacasmayo — In November 2003, we completed the sale of Cahua and Energia Pacasmayo resulting in net cash proceeds of approximately $16 million and a loss of $37 million. In addition, we received an additional consideration adjustment of approximately $1 million during 2004.

Note 7 — Write Downs and (Gains)/Losses on Sales of Equity Method Investments

Investments accounted for by the equity method are reviewed for impairment in accordance with APB 18 which requires that a loss in value of an investment that is other than a temporary decline should be recognized. Gains or losses are recognized on completion of the sale. Write downs and (gains)/losses on sales of equity method investments recorded in other income/expense in the consolidated statement of operations includes the following:

		Reorganized NRG			Predecessor Company
	Segment	Year Ended December 31, 2005	Year Ended December 31, 2004	For the Period December 6 - December 31, 2003	For the Period January 1 - December 5, 2003
		(In millions)			
Saguaro	Western	$ 27	$ —	$ —	$ —
Rocky Road	Other North America	20	—	—	—
Kendall	Other North America	(4)	—	—	—
Enfield	Other International	(12)	—	—	—
Commonwealth Atlantic Limited Partnership	Other North America	—	5	—	—
James River Power LLC	Other North America	—	7	—	—
NEO Corporation	Alternative Energy	—	4	—	—
Calpine Cogeneration	Other North America	—	(1)	—	—
NLGI — Minnesota Methane	Alternative Energy	—	—	—	12
NLGI — MM Biogas	Alternative Energy	—	—	—	3
ECKG	Other International	—	—	—	(3)
Loy Yang	Australia	—	1	—	146
Mustang	Other North America	—	—	—	(12)
Other		—	—	—	1
Total write downs and losses on sales of equity method investments		$ 31	$ 16	$ —	$ 147

Saguaro — During the fourth quarter of 2005, due to the expiration of its long-term gas supply contract and higher market prices paid for natural gas, NRG determined that a decline in the value of its 50% investment in Saguaro was considered to be permanent and recorded a write down of its investment of approximately $27 million.

Rocky Road — In December 2005, NRG entered into a purchase and sale agreements (PSA) with Dynegy, Inc. whereby we have agreed to sell to Dynegy our 50% ownership interest in Rocky Road Power LLC for $45 million cash. As a result of the PSA with Dynegy, during December 2005, we recorded an impairment charge of approximately $20 million to write down the value of our 50% interest in Rocky Road to the fair value of $45 million.

Kendall — In December 2004, we sold out interest in Kendall to LS Power Associates, L.P. or LS Power. Under the terms of the December 2004 agreement, we retained the right to acquire a 40% interest in the plant within a 10-year period for a nominal amount, or the Call Option. Therefore, the transaction was treated as a partial sale for accounting purposes. On August 8, 2005, we executed an agreement with LS Power to sell the Call Option for $5 million. A pre-tax gain of $4 million was recognized in the third quarter of 2005.

Enfield — On April 1, 2005, we completed the sale of our 25% interest in Enfield to Infrastructure Alliance Limited. The sale resulted in net pre-tax proceeds of $65 million. A pre-tax gain of approximately $12 million was recorded in the second quarter of 2005.

Commonwealth Atlantic Limited Partnership (CALP) — In June 2004, we executed an agreement to sell our 50% interest in CALP. During the third quarter of 2004, we recorded an impairment charge of approximately $4 million to write down the value of our investment in CALP to its fair value. The sale closed in November 2004 resulting in net cash proceeds of $15 million. Total impairment charges as a result of the sale were approximately $5 million.

James River Power LLC — In September 2004, we executed an agreement with Colonial Power Company LLC to sell all of our outstanding shares of stock in Capistrano Cogeneration Company, a wholly-owned subsidiary of NRG Energy which owns a 50% interest in James River Cogeneration Company at which time we recorded an impairment charge of approximately $6 million to write down the value of our investment in James River to its fair value. During the fourth quarter of 2004, the sales agreement was terminated. Total impairment charges for 2004 were approximately $7 million.

NEO Corporation — On September 30, 2004, we completed the sale of several NEO investments — Four Hills LLC, Minnesota Methane II LLC, NEO Montauk Genco LLC and NEO Montauk Gasco LLC to Algonquin Power of Canada. The sale also included four wholly-owned NEO subsidiaries (see Note 6). We received cash proceeds of approximately $6 million. The sale resulted in a loss of approximately $4 million attributable to the equity investment entities sold.

Calpine Cogeneration — In January 2004, we executed an agreement to sell our 20% interest in Calpine Cogeneration Corporation to Calpine Power Company. The transaction closed in March 2004 and resulted in net cash proceeds of $3 million. During the second quarter of 2004, we received additional consideration on the sale of $1 million, resulting in an adjusted net gain of $1 million.

NLGI — Minnesota Methane —. We recorded an impairment charge of $15 million during the first quarter of 2003. This charge was related to a revised project outlook and management's belief that the decline in fair value was other than temporary. In May 2003, the project lenders to the wholly-owned subsidiaries of NEO Landfill Gas, Inc. and Minnesota Methane LLC foreclosed on our membership interest in the NEO Landfill Gas, Inc. subsidiaries and our equity interest in Minnesota Methane LLC. Upon completion of the foreclosure, we recorded a gain of $2 million resulting in a net impairment charge of $12 million. The gain upon completion of the foreclosure resulted from the release of certain obligations upon completion of the foreclosure.

NLGI — MM Biogas — In November 2003, we entered into a sales agreement with Cambrian Energy Development to sell our 50% interest in MM Biogas. We recorded an impairment charge of $3 million during the fourth quarter of 2003 due to developments related to the sale that indicated an impairment of our book value that was considered to be other than temporary.

ECKG — In September 2002, we announced that we had reached agreement to sell our 44.5% interest in the ECKG power station in connection with our Csepel power generating facilities, and our interest in Entrade, an electricity trading business, to Atel, an independent energy group headquartered in Switzerland.

The transaction closed in January 2003 and resulted in cash proceeds of $65 million and a net loss of less than $1 million. In accordance with the purchase agreement, we were to receive additional consideration if Atel purchased shares held by our partner. During the second quarter of 2003, we received approximately $4 million of additional consideration resulting in a net gain of approximately $3 million.

Loy Yang — In May 2003, we entered into negotiations that culminated in the completion of a Share Purchase Agreement to sell 100% of the Loy Yang project. Consequently, we recorded an impairment charge of approximately $146 million during 2003. In April 2004 we completed the sale of Loy Yang which resulted in net cash proceeds of approximately $27 million and a loss of approximately $1 million.

Mustang Station — On July 7, 2003, we completed the sale of our 25% interest in Mustang Station, a gas-fired combined cycle power generating plant located in Denver City, Texas, to EIF Mustang Holdings I, LLC. The sale resulted in net cash proceeds of approximately $13 million and a net gain of approximately $12 million.

Note 8 — Other Charges (Credits)

Other charges and credits included in operating expenses in the Consolidated Statement of Operations include the following:

	Reorganized NRG			Predecessor Company
	Year Ended December 31, 2005	Year Ended December 31, 2004	For the Period December 6 - December 31, 2003	For the Period January 1 - December 5, 2003
	(In millions)			
Corporate relocation charges	$ 6	$ 16	$ —	$ —
Reorganization items	—	(13)	2	198
Impairment charges	6	45	—	229
Restructuring charges	—	—	—	8
Fresh Start adjustments	—	—	—	(4,220)
Legal settlement	—	—	—	463
Total	$ 12	$ 48	$ 2	$ (3,322)

Corporate Relocation Charges

On March 16, 2004, we announced plans to implement a new regional business strategy and structure. The new structure called for a reorganized leadership team and a corporate headquarters relocation to Princeton, New Jersey. As of December 31, 2004, the transition of our corporate headquarters is substantially complete.

For the years ended December 31, 2005 and 2004, we recorded $6 million and $16 million, respectively, for total charges of $22 million related to our corporate relocation activities, primarily for employee severance and termination benefits and employee related transition costs and lease abandonment costs. These charges are classified separately in our statement of operations, in accordance with SFAS No. 146, *"Accounting for Costs Associated with Exit or Disposal Activities"*, or SFAS 146. All material expenses related to the corporate relocation have been incurred as of December 31, 2005. Lease termination costs require that cash payments in the amount of $2 million be made through the fourth quarter of 2006.

A summary of the SFAS 146-classified expenses is as follows:

	Year Ended December 31, 2004	Year Ended December 31, 2005	Yet to be Incurred	Expected Total Charges
		(In millions)		
Employee related transition costs	$ 9	$ 2	$ —	$ 11
Severance and termination benefits...	6	1	—	7
Lease termination costs.............	1	3	—	4
Total corporate relocation charges..	$ 16	$ 6	$ —	$ 22

A summary of the significant components of the restructuring liability is as follows:

	Balance at December 31, 2004	Relocation Related Charges	Cash Payments	Balance at December 31, 2005
		(In millions)		
Employee related transition costs	$ (1)	$ 2	$ (1)	$ —
Severance and termination benefits	4	1	(5)	—
Lease termination costs	1	3	(2)	2
Total............................	$ 4	$ 6	$ (8)	$ 2

As of December 31, 2005 and 2004, the net restructuring liability was approximately $2 million and $4 million, respectively, the majority of which is included in other current liabilities on the consolidated balance sheet. Charges related to the employee related transition costs, severance and termination benefits and lease termination costs are recorded at our corporate level within our All Other — Other segment, in the corporate relocation charges line on the consolidated statement of operations.

Reorganization Items

For the year ended December 31, 2005 we did not record any reorganization item expense or income. For the year ended December 31, 2004, we recorded a net credit of approximately $13 million related primarily to the settlement of obligations recorded under Fresh Start. For the periods December 6, 2003 to December 31, 2003 and January 1, 2003 to December 5, 2003, we incurred approximately $2 million and $198 million, respectively, in reorganization costs. All reorganization costs have been incurred since we filed for bankruptcy in May 2003. The following table provides the detail of the types of costs incurred.

	Reorganized NRG			Predecessor Company
	Year Ended December 31, 2005	Year Ended December 31, 2004	For the period December 6 - December 31, 2003	For the Period January 1 - December 5, 2003
	(In millions)			
Reorganization items				
Professional fees	$ —	$ 7	$ 2	$ 82
Deferred financing costs	—	—	—	55
Pre-payment settlement	—	—	—	20
Interest earned on accumulated cash	—	—	—	(1)
Contingent equity obligation	—	—	—	42
Settlement of obligations and other gains	—	(20)	—	—
Total reorganization items	$ —	$ (13)	$ 2	$ 198

Impairment Charges

We review the recoverability of our long-lived assets in accordance with the guidelines of SFAS 144. As a result of this review, we recorded impairment charges of approximately $6 million, $45 million and $229 million, for the years ended December 31, 2005 and 2004, and the period January 1, 2003 through December 5, 2003, respectively, as shown in the table below.

To determine whether an asset was impaired, we compared asset-carrying values to total future estimated undiscounted cash flows. If an asset was determined to be impaired based on the cash flow testing performed, an impairment loss was recorded to write down the asset to its fair value.

Impairment charges (credits) included the following asset impairments (realized gains) for the years ended December 31, 2005 and 2004, and the period January 1, 2003 to December 5, 2003. There were no impairment charges for the period December 6, 2003 to December 31, 2003.

		Reorganized NRG		Predecessor Company	
Project Name	Project Status	Year Ended December 31, 2005	Year Ended December 31, 2004	For the Period January 1 — December 5, 2003	Fair Value Basis
		(In millions)			
Berrians I Gas Turbine Power LLC	Non-operating asset	$ 6	$ —	$ —	Sales price
Meriden (turbine only)	Pending sale	—	15	—	Sales price
Kendall	Sold	—	27	—	Realized loss
Louisiana Generating LLC	Office building and land being marketed	—	1	—	Estimated market price
New Roads Holding LLC (turbine)	Non-operating asset — abandoned	—	2	—	Projected cash flows
Devon Power LLC	Operating at a loss in 2003	—	—	64	Projected cash flows
Middletown Power LLC	Operating at a loss	—	—	157	Projected cash flows
Arthur Kill Power, LLC	Terminated construction project	—	—	9	Projected cash flows
Langage (UK)	Terminated	—	—	(3)	Estimated market price/Realized gain
Turbines	Sold	—	—	(22)	Realized gain
Berrians Project	Terminated	—	—	14	Realized loss
TermoRio	Terminated	—	—	7	Realized loss
Other		—	—	3	
Total impairment charges		$ 6	$ 45	$ 229	

Berrians I Gas Turbine Power LLC — During 2005, we determined that an unused turbine previously acquired for a now canceled project would be placed for sale. A letter of intent was entered into for the sale which resulted in an impairment of approximately $6 million, and the sale closed during the first quarter of 2006. Berrians is included within our Other North America segment. The balance of the Berrians turbine is classified as a current asset held for sale on the balance sheet as of December 31, 2005, totaling $8 million.

Meriden — During the third quarter of 2004, we entered into a purchase and sale agreement to sell unused turbines. As a result, we recorded an impairment charge of $15 million. The sale is expected to close in the first half of 2006. Meriden is included in our All Other segment under the Other category. The balance of the Meriden turbines are classified as current assets held for sale on the balance sheet as of December 31, 2005, totaling $35 million.

Kendall — In September 2004, we executed an agreement to sell our 1,160 MW generating plant in Minooka, Illinois to an affiliate of LS Power Associates, L.P and recorded a charge of approximately $25 million related to the impairment to realizable value. Under the terms of the agreement, we have the right to acquire a 40% interest in the plant within a 10-year period for a nominal amount. Therefore, the transaction was treated as a partial sale for accounting purposes. In December 2004 we completed the sale and received net proceeds of $1 million, resulting in a loss on sale of approximately $2 million and a total loss of approximately $27 million. Kendall is included in our Other North America segment.

Louisiana Generating LLC — In January 2004, we closed the South Central regional office in Baton Rouge, Louisiana and offered it for sale. During the fourth quarter of 2004, we recorded a charge of approximately $1 million related to the impairment to net realizable value based on two offers received. The sale was finalized during the third quarter of 2005. Louisiana Generating is included in our South Central segment.

New Roads Holding LLC — During the second quarter of 2004, we reviewed the recoverability of our New Roads assets pursuant to SFAS No. 144 and recorded a charge of approximately $1 million related to the impairment to realizable value of a turbine acquired in March 2000 from Cajun Electric. During the third quarter of 2004, we recorded an additional charge of approximately $1 million to write the turbine's value down to its scrap value. New Roads Holding is included in our South Central segment.

Connecticut Facilities (Devon Power LLC and Middletown Power LLC) — As a result of regulatory developments and changing circumstances in the second quarter of 2003, we updated the facilities' cash flow models to incorporate changes to reflect the impact of the April 25, 2003 FERC's orders on regional and locational pricing, and to update the estimated impact of future locational capacity or deliverability requirements. Based on these revised cash flow models, management determined that the new estimates of pricing and cost recovery levels were not projected to return sufficient revenue to cover the fixed costs at Devon Power LLC and Middletown Power LLC. As a consequence, during the second quarter of 2003 we recorded approximately $64 million and $157 million as impairment charges for Devon Power LLC and Middletown Power LLC, respectively. In the third quarter of 2004, ISO-NE informed the Company that it would not extend the RMR contract for Devon units 7 and 8. As a result, both units have been placed on deactivated reserve. Devon Power and Middletown Power are included in our Northeast segment.

Arthur Kill Power, LLC — During the third quarter of 2003, we cancelled our plans to re-establish fuel oil capacity at our Arthur Kill plant. This resulted in a charge of approximately $9.0 million to write-off assets under development. Arthur Kill Power is included in our Northeast segment.

Langage (UK) — In August 2003 we closed on the sale of Langage to Carlton Power Limited resulting in net cash proceeds of approximately $2 million, of which $1 million was received in 2003 and $1 million was received during the first quarter of 2004, and a net gain of approximately $3 million. Langage is included in our All Other segment under the Other International category.

Turbines — In October 2003, we closed on the sale of three turbines and related equipment. The sale resulted in net cash proceeds of approximately $71 million and a gain of approximately $22 million. Turbines are included in our All Other segment under the Other category.

Berrians Project — During the fourth quarter of 2003, we cancelled plans to construct the Berrians peaking facility on the land adjacent to our Astoria facility. Berrians was originally scheduled to commence operations in the summer of 2005; however, based on the remaining costs to complete and the current risk profile of merchant peaking units, the construction project was terminated. This resulted in a charge of approximately $14 million to write off the project's assets. Berrians is included in our Other North America segment.

TermoRio — TermoRio was a green field cogeneration project located in the state of Rio de Janeiro, Brazil. Based on the project's failure to meet certain key milestones, we exercised our rights under the project agreements to sell our debt and equity interests in the project to our partner, Petroleo Brasileiro S.A. Petrobras, or Petrobras. On May 17, 2002, Petrobras commenced an arbitration. On March 8, 2003, the arbitral tribunal decided most, but not all, of the issues in our favor and awarded us approximately US $80 million. On June 4, 2004, NRG Energy commenced a lawsuit in U.S. District Court for the Southern District of New York, seeking to enforce the arbitration award. On February 16, 2005, a conditional settlement agreement was signed with our former partner Petrobras, whereby Petrobras is obligated to pay us $71 million. Such payment was received by us at a closing held on February 25, 2005. We had a note receivable of $57 million related to the arbitration award. The amounts received in excess of approximately $57 million were recorded to other income in the first quarter of 2005. TermoRio is included in our All Other segment under the Other International category. A $3 million reserve related to ongoing litigation was recorded in the fourth quarter of 2005.

Restructuring Charges

We incurred $8 million of employee separation costs and advisor fees during 2003 until we filed for bankruptcy in May 2003. Subsequent to that date we recorded all advisor fees as reorganization costs.

Fresh Start Adjustments

During the fourth quarter of 2003, we recorded a net credit of $3.9 billion (comprised of a $4.2 billion gain from continuing operations and a $0.3 billion loss from discontinued operations) in connection with fresh start adjustments as discussed in Note 3.

Following is a summary of the significant effects of the reorganization and Fresh Start:

	(In millions)
Discharge of corporate level debt	$ 5,162
Discharge of other liabilities	811
Establishment of creditor pool	(1,040)
Receivable from Xcel	640
Revaluation of fixed assets	(1,392)
Revaluation of equity investments	(207)
Valuation of SO(2) emission credits	374
Valuation of out of market contracts, net	(400)
Fair market valuation of debt	108
Valuation of pension liabilities	(61)
Other valuation adjustments	(100)
Total Fresh Start adjustments	3,895
Less discontinued operations	(325)
Total Fresh Start adjustments — continuing operations	$ 4,220

Legal Settlement Charges

During the period January 1, 2003 to December 5, 2003, we recorded $463 million of legal settlement charges which consisted of the following. We recorded $396 million in connection with the resolution of an arbitration claim asserted by FirstEnergy Corp. As a result of this resolution, FirstEnergy retained ownership of the Lake Plant Assets and received an allowed general unsecured claim of $396 million under NRG Energy's Plan of Reorganization. In November 2003, we settled litigation with Fortistar Capital in which Fortistar Capital released us from all litigation claims in exchange for a $60 million pre-petition bankruptcy claim and an $8 million post-petition bankruptcy claim. We had previously recorded $11 million in connection with various legal disputes with Fortistar Capital; accordingly, we recorded an additional $57 million during November 2003. In November 2003, we settled our dispute with Dick Corporation in connection with Meriden Gas Turbines LLC through the payment of a general unsecured claim and a post-petition pre-confirmation payment. This settlement resulted in our recording an additional liability of $8 million in November 2003.

In August 1995, we entered into a Marketing, Development and Joint Proposing Agreement, or the Marketing Agreement, with Cambrian Energy Development LLC, or Cambrian. Various claims arose in connection with the Marketing Agreement. In November 2003, we entered into a settlement agreement with Cambrian where we agreed to transfer our 100% interest in three gasco projects (NEO Ft. Smith, NEO Phoenix and NEO Woodville) and our 50% interest in two genco projects (MM Phoenix and MM Woodville) to Cambrian. In addition, we paid approximately $2 million in settlement of royalties incurred in connection with the Marketing Agreement. We had previously recorded a liability for royalties owed to Cambrian, therefore, we recorded an additional $1 million during November 2003.

Note 9 — Asset Retirement Obligation

Effective January 1, 2003, we adopted SFAS 143 which requires an entity to recognize the fair value of a liability for an asset retirement obligation in the period in which it is incurred. Upon initial recognition of a liability for an asset retirement obligation, an entity shall capitalize an asset retirement cost by increasing the carrying amount of the related long-lived asset by the same amount as the liability. Over time, the liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Retirement obligations associated with long-lived assets included within the scope of SFAS 143 are those for which a legal obligation exists under enacted laws, statutes and written or oral contracts, including obligations arising under the doctrine of promissory estoppel.

We identified certain retirement obligations within our power generation operations in the Northeast, South Central and Australia regions. We also identified retirement obligations within our All Other segment under the Other International, Alternative Energy category and the Non-Generation category. These asset retirement obligations are related primarily to the future dismantlement of equipment on leased property and environment obligations related to ash disposal site closures and fuel storage facilities.

We have also identified conditional asset retirement obligations for asbestos removal and disposal which are specific to certain power generation operations. In 2005, we adopted FIN 47 which clarifies the term "conditional asset retirement obligation" as used in SFAS 143. Under FIN 47, a conditional asset retirement obligation is reasonably estimable if (a) it is evident that the fair value of the obligation is embodied in the acquisition price of the asset, (b) an active market exists for the transfer of the obligation, or (c) sufficient information exists to apply an expected present value technique. To estimate the fair value of the conditional asset retirement obligations, we utilize existing information to calculate an expected present value of the future obligations. The existing information includes engineering estimates on the cost of asbestos removal and disposal, the maximum future lives of the plants assuming no major renovations, our weighted average cost of capital and future inflation rates. We also include several probabilities in the expected present value calculation, including major plant renovations or dismantlement. The calculation of the expected present value of the conditional asset retirement obligations indicates an additional asset retirement obligation for asbestos removal and disposal of $4 million which we recorded in the fourth quarter of 2005. The cumulative effect adjustment of the additional asset retirement obligation is not considered to be material.